EXHIBIT NO. ___(CEP-1T)
DOCKET NO. UE-04____/UG-04____
2004 PSE GENERAL RATE CASE
WITNESS: COLLEEN E. PAULSON

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-04____ Docket No. UG-04____

PREFILED DIRECT TESTIMONY OF
COLLEEN E. PAULSON (NONCONFIDENTIAL)
ON BEHALF OF PUGET SOUND ENERGY, INC.

APRIL 5, 2004

PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Colleen E. Paulson and my business address is 10885 N.E. Fourth Street, Bellevue, Washington 98004. I am employed by Puget Sound Energy ("PSE") as a Manager of Pricing & Cost of Service.

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(CEP-2).

II. PURPOSE

Q: What are the topics you will be covering in your testimony?

A: I am sponsoring the Company's gas and electric cost of service studies. These two studies translate the gas and electric revenue requirements into assignment of revenues, operating expenses, and ratebase at the customer class level. These studies follow the traditional approach of separating costs by major utility functions (cost functionalization), classification of the costs (i.e. throughput, capacity, customer) and allocation of the costs to the customer rate classes. Where possible, I used accounting records and special studies to directly allocate costs rather than use allocation factors to separately split up joint costs. The cost of service studies are used by Mr. James Heidell as a guide to the Company's rate spread proposal. My testimony first addresses natural gas cost of service and then electric cost of service.

III. NATURAL GAS COST OF SERVICE STUDY

Q: Please explain the underlying considerations of the cost of service study.

A: The study is based on the previous cost of service methodology accepted by the Commission for Washington Natural Gas Company (WNG) in Docket No. UG-940814, which was also applied in the settlement of PSE's last general rate case, Docket No. UG-011571. The Company's focus in this case was not on developing or arguing for different methodologies. Instead, the focus was on improving cost assignment through attention to the direct assignment of costs rather than joint allocation of costs.

Q: Are there any other changes the Company implemented in preparing the cost of service study?

A: Yes, PSE developed a cost of service model to standardize its electric and gas cost of service analyses and reports. The model was benchmarked against the model used in the last rate case to ensure that any changes in results are the outcome of the model inputs and not the new model.

Q: What are the load characteristics of the rate classes in the cost of service

study?

A: I have summarized the relevant load characteristics of the Company's various customer groups in Exhibit No. ___ (CEP-5). It is important to recognize that for each class of service, the absolute and relative level of certain of these load characteristics has a direct influence on the type and level of costs incurred by the Company in serving those customers.

Q: What are the implications of class load characteristics for purposes of allocating joint costs associated with serving PSE customers?

A: First, annual load factor is an important indicator of how a customer utilizes PSE's pipeline capacity. As a customer's annual load factor increases, it indicates that the customer is using the Company's system capacity more efficiently than a lower load factor customer. In addition, peak-day demand is a key element in the sizing of the Company's facilities and in determining the level of costs incurred in serving its customers. Although the day-to-day utilization of the Company'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: How have the costs of the Company's transmission and delivery system been classified and allocated in the cost of service study?

A: The Company used the "five highest peaks" method for determining the demand

and commodity cost components. This classification is based on the Company's system annual load factor derived on a peak-day basis. The peak day is determined by the average of the Heating Degree-Days (HDDs) of the observed five highest peaks the Company experienced during December 2002 through January 2004. This method results in a peak day demand for the Company of approximately 6,962,075 therms based on a 38 HDD level.

Q: Under the Company's proposed method, what were the weather conditions actually experienced for the five highest peaks in the last three years?

A: The following table presents this information:

Date	**Average Temperature**	**HDDs**
January 5, 2004	24°F	42
January 4, 2004	23°F	41
January 3, 2004	29°F	35
January 6, 2004	26°F	38
December 29, 2003	32°F	32
Average	**27°F**	**38**

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

A: The Company started with an analysis of facilities used to serve its largest customers - Rate Schedules 85, 87, 57 and the special contract customers. The study identified the dedicated plant investment that could be directly assigned to these customers. Each customer's location on the Company's distribution system was determined and plant investment data was compiled to develop the cost of the distribution mains dedicated to serve the customer. All mains were traced upstream to a source gate station. Since, the study results indicated that most commercial and industrial customers are served off of distribution mains four inches or larger in diameter, the Company disaggregates the distribution main investment into two subgroups; mains four inches or greater and mains less than four inches in diameter. The costs of the dedicated mains were then directly assigned to the largest customer group. The remaining plant balance for mains four inches or greater are classified between demand and commodity on a system load factor basis and allocated to Rate Schedules 31, 41 and 86 customers based on peak day demand and commodity throughput allocation factors. Mains less than 4 inches in diameter are classified in the same manner and were allocated to all customers except Rate Schedules 85, 87, 57 and the special contract customers.

Q: In conjunction with the above-described analysis of distribution mains, were there other facilities identified which could be directly assigned to these larger customers?

A: Yes, the cost of service lines were directly assigned to the Rate Schedules 85, 87, 57 and the special contract customers.

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

A: Weighting factors were applied to the plant accounts, net of directly assigned costs, to allocate the remaining costs to each class based on the type of equipment typically or actually used by each class. The Company used this approach for service lines, meters and regulators.

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. These standards were the basis for identifying the typical size and type of service line for each customer group. With regard to meters and industrial measuring and regulatory (M&R) station equipment, the Company conducted a detailed analysis of data contained in its customer information system to identify 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: How did the study allocate distribution-related operation and maintenance expenses?

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

Q: How did the study allocate purchased gas expenses?

A: The Company's study classifies purchased gas costs into two components: demand and commodity. The commodity-related costs include contract commodity, 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 allocated to the Company's customer classes according to throughput and peak demand allocation factors (i.e., using peak demands, winter season sales and annual sales).

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

A: The reservation charges associated with winter contracts were classified as demand costs and allocated on a winter seasonal basis. Firm transportation demand charges related to pipeline supplies were allocated using the five highest peaks 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 the variable or commodity-related gas costs allocated?

A: All variable gas costs were classified as commodity costs. Peaking supply-related charges were allocated on a peak day demand basis. Pipeline costs related to Jackson Prairie were allocated on a seasonal basis. The rest of the variable gas costs were allocated on annual sales as described in the listing of resources in Exhibit No. ___ (CEP-3), pages 11-12.

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

taxes to each customer class?

A: Administrative and general expenses were allocated on a specific account-by-account basis and by the following expense category: (1) labor; (2) plant; and (3) combined. Operating income before interest expenses and Federal income taxes (EBIT) was determined for each class. Current and deferred income taxes were allocated to each class based on its relative EBIT to the total EBIT.

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

A: Referring to the Summary of Natural Gas Cost Study Results, Exhibit No. ___ (CEP-3), the following results at present rates are indicated:

Class	Parity Ratio	Rate of Return
Residential 23/53/16	95%	5.68%
C & I Heating 31/36/61/51	119%	9.18%
C & I – 41	131%	10.68%
Rate Schedule 85	80%	3.62%
Rate Schedule 86	98%	6.39%
Rate Schedule 87	51%	-2.25%
Rate Schedule 57	171%	15.97%
Special Transport Contracts 99/199/299	77%	2.62%
CNG Service 50	9%	-41.15%
Rentals 71/72/74/75	59%	-6.85%

Company	100%	6.38%

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

A: Yes, I have. Included in Exhibit No. ___ (CEP-4) at pages 10-11 are details of the cost-based customer charge. 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 related administrative and general (A&G) expenses. The study also calculates the return on net ratebase allowed on the Company's meters, services, and other distribution and general plant investment.

IV. RESTATING AND PROFORMA ADJUSTMENTS TO NATURAL GAS CLASS REVENUES

Q: Have you prepared exhibits to summarize the calculation of proforma class revenues?

A: Yes, Exhibit No. ___ (CEP-6) details the restating adjustments made outside of the Gas Proforma Revenue Model. Exhibit No. ___ (CEP-7) shows the restating adjustments calculated in the model, specifically: (1) the elimination of adjusting schedule revenues and municipal taxes, and certain propane sales, (2) normal degree days; (3) test year base rate levels; and (4) current gas cost levels as approved by the Commission effective October 1, 2003, in the Company's last PGA filing.

Q: Would you please describe the adjustments in Exhibit No. ___ (CEP-7)?

A: The adjustments remove municipal taxes, propane sales and associated revenues (pursuant to the Commission's Fourth Supplemental Order in Docket No. UG-920840), as well as Rate Schedules 106, 120, 129 and 107.

The second part of the adjustment reflects the difference between the actual rates and the base rates in effect during the test year. Utilizing the monthly sales and transportation volumes, and pricing them at test year monthly base rate, results in revenues as shown in column (aa) of Exhibit No. ___ (CEP-7), page 3 of 5. The restating base rate adjustment of ($4,396,452) is recorded in column (ad), page 3, line 25.

Q: Please summarize the weather adjustment?

A: This adjustment is made to reflect consumption expected under normal weather conditions. The Company calculated normal weather by using the Commission-approved approach of calculating an 18-year moving average of past annual heating degree days ("HDDs"). The moving average is calculated using a 20-year historical period with the highest and lowest years excluded (Docket No. UG-920840, Fourth Supplemental Order, p. 17). This analysis results in a definition of normal weather for the test period of 4,690 HDDs. Actual heating degree days for the test period were 4,454 HDDs. Annual consumption, adjusted to normal year weather, is 1,019,920,884 therms, as shown on line 25, column (af) of Exhibit No. ___ (CEP-7), page 3.

Revenues corresponding to these normalized therms are then calculated by applying the base rates in effect during each month of the test year to the normalized sales and transportation throughput. The sum of the monthly revenue calculations is shown in column (ag). The resulting restating adjustment of ($16,212,763) is shown in column (ak) of line 25. The final (proforma) adjustment equals ($98,373,580), as shown in column (ap) on line 25 of Exhibit No. ___ (CEP-7), page 4. This adjustment reprices the normalized monthly therms using gas cost levels effective October 2002. The resulting revenues are $704,140,084 as shown in column (am) of Exhibit No. ___ (CEP-7), page 4.

Q: How are these adjustments reflected in the Company's revenue requirement?

A: These adjustments are reflected on Ms. Luscier's, Exhibit No. ___ (BAL-G3), page G3-A, Column 2.01 and the resulting proforma revenues are shown as the total adjusted operating revenues in the Summary of Exhibit No. ___ (BAL-G3).

Q: What total gas revenue requirement is the Company utilizing in its proposal?

A: The Company has used a gas revenue requirement of $1,064,289,535, not including municipal additions. This total revenue requirement is shown on Ms. Luscier's Exhibit No. ___ (BAL-G3), Summary page.

V. ELECTRIC COST OF SERVICE

Q. Have you prepared a cost of service study to allocate the electric revenue requirement presented in Mr. Story's testimony?

A. Yes, the results of the cost of service study are presented in Exhibit No.___(CEP-8).

Q. Is the Company proposing changes to the electric cost of service methodology?

A. The Company is proposing a few changes to the cost of service methodology that was last reviewed in the combined rate design case and general rate case in Docket Nos. UE-921262 and UE-920499 ("1992 rate design case"). These changes address the Company's objective of having the distinct customer groups pay their fair share of costs. Since the Commission reviewed cost of service methodology in the 1992 rate design case, the Company has made changes in its information systems and it is now possible to better relate the cost of electric distribution facilities to the different customer classes. The Company has retained the peak credit method for classifying and allocating generation and transmission. Non-coincident peak loads are used to allocate distribution costs. However, with improved reporting systems, in regard to plant, it is possible to rely more on the principles of direct assignment of costs for allocation of distribution system costs.

Q. What changes have been made to cost of service classification or allocation

procedures since the last Commission-approved cost of service methodologies?

A. The last Commission-approved electric cost of service methodologies resulted from the 1992 rate design case. Subsequent rate adjustments have been made based on stipulations with tacit agreements by the parties to utilize the past Commission-approved cost of service methodologies, while not agreeing that the historical methods are necessarily correct. In PSE's 2001 general rate case, Docket No. UE-011570, the Company incorporated two necessary changes. First, a new class was created for the large load retail customers that secure their own electricity. Second, the Company separated the transmission system as described in Docket No. UE-010010. Those changes are included in the Company's cost of service for this case. The Company is also proposing additional changes including new mechanisms for weather adjustment of demand and energy allocation factors and new electric distribution cost allocation factors.

Q. Why are you proposing to modify Commission-approved cost of service classification and allocation methods?

A. In the past decade, there have been significant changes within the industry, the types of service provided to customers, and the Company's information systems. These changes warrant reconsideration of some of the Commission directives established in the 1992 rate design case and cases prior to 1992.

Q. What types of changes has the Company made to the cost of service

procedures approved by the Commission in the 1992 rate design case?

A. I have grouped the summary of cost classification and allocation procedures into five major categories: (1) adjustment of billing determinants for demand and energy allocation; (2) energy and demand allocation factors associated with production costs; (3) non-generation related transmission cost allocation; (4) distribution cost allocation; and (5) A&G / common cost allocations. Each of these categories has some components of the cost allocation procedures that have not changed from the 1992 rate design case, as well as components that have changed. I summarize the unchanged procedures, then describe the changes in greater detail.

A. Adjustment of Billing Determinants

Q. What is the role of billing determinants in preparation of the cost of service study?

A. Billing determinants are used to allocate power production and bulk transmission related costs. These costs account for approximately two-thirds of the costs allocated in the cost of service study. Power costs are classified as either energy or demand. These two components are respectively allocated to each class based upon the class contribution to total system energy use and coincident peak demand. Power production costs in this case are based upon energy requirements for the rate year (proforma to the test year by the production factor) assuming normal temperature and an average historic hydro condition. When the weather in the test year is either warmer or colder than normal there is a mismatch between the proforma energy and the determinants used to allocate production costs. There is also a mismatch when the customer mix differs significantly between the test and rate year. Temperature adjustments are used to proform test year residential sales to reflect normal weather, and an adjustment was made to remove large power customers who will be securing their own power. The result is that the energy allocations are consistent with the normalized power costs for the rate year. The mechanics of the adjustment are described by Mr. James Heidell in his testimony, Exhibit No. ____(JAH-1T).

B. Production Cost Allocation

Q. What costs are functionalized as production and how are they classified and allocated?

A. Fixed and variable production costs are classified as energy or demand. In addition, the costs of transmission used to integrate remote generation are functionalized, classified, and allocated in the same manner as production costs. Transmission integration costs include both Company-owned transmission and wheeling costs associated with integrating remote generation. Production costs and production-related transmission costs are classified as either demand or energy according to the peak credit method. These costs are then allocated to the class based upon class temperature plus loss-adjusted energy use (the energy portion) and the class' contribution to the load during the system's 200 peak hours (the demand portion). The 200 peak hours were normalized according to procedures outlined by Mr. James Heidell in his testimony.

Q. Please briefly describe the peak credit classification method and how it has been calculated.

A. The peak credit calculation is used to classify production costs into energy and capacity components. The peak credit method has been accepted by the Commission as a reasonable way to evaluate capacity costs on a combined hydro storage and thermal system. The peak credit estimates the proportion of production cost that is capacity related by dividing the cost of a proxy capacity resource by a proxy base load generation resource. This classification method is important since it is applied to production and transmission cost and influences the allocation of approximately two thirds of the revenue requirement. This results in 13% of the production cost being demand related. This calculation was done using inputs from PSE's 2003 Least Cost Plan and is shown in Exhibit No.___ (CEP-10).

C. Non-Generation Related Transmission Cost Allocation

Q. How have transmission costs been classified and allocated?

A. Transmission costs are separated into three categories. The first category is transmission that is used to integrate distant generation and to provide access to distant markets for the purpose of lowering power costs. These costs are allocated to the rate classes based upon the generation cost allocation factors.

The remainder of the system is further separated into two categories based upon the FERC seven factor test. The application of the seven factor test was reviewed by the Commission in UE-010010. The two categories are referred to as bulk transmission and sub-transmission for the purpose of this cost of service study. I have not adopted the FERC classification of "distribution" since I have reserved that term for the retail power distribution system that existed prior to the Company's reclassification filing with the Commission. Both the bulk and sub-transmission systems are classified as demand and energy in accordance with the peak credit method and allocated to the customer classes based upon the 200 CP method. However, Rate Schedule 448 and 449 customers are excluded from the 200 CP calculation for allocation of bulk transmission costs.

<u>D. Distribution Cost Allocation</u>

Q. How were distribution plant costs allocated?

A. The Company directly allocated meter and line transformer costs using separate allocators derived from an analysis of installed meters and line transformers used by each class. The current equipment inventory was directly assigned to each class and the equipment was priced at current costs. The ratios of each class' contribution to the total cost were then applied to embedded costs to construct forward-looking cost allocation. The cost of underground circuits, overhead circuits, and substations were assigned based upon allocation factors constructed from each class' contribution to the feeder's and substation's peak and the length of the distribution circuit. The allocation factors were constructed from monthly energy and load factors for the twelve-month period ending in September 2003.

Q. Does this method differ from the approach approved by the Commission in the 1992 rate design case?

A. Yes. However, the primary difference is in the level of detail rather than a difference in philosophical approach. For example, in the last approved cost of service study, distribution and substation costs were allocated at the system level based upon non-coincident peak demands. In this case, the Company took advantage of its databases to allocate these costs at a circuit and substation level based upon non-coincident peak demands. This is more equitable, since classes that do not use a distribution feeder should not be assigned any cost for that feeder.

In general, direct assignment of costs is preferable to increase the accuracy of the cost causation study. In its study, the Company moved toward a more direct cost assignment of line transformer costs. In the 2001 general rate case, the Company directly assigned meters to each class and has used that approach in this study.

Q. Would you please describe how the transformer cost allocation factors were developed?

A. The Company used its customer database to associate each line transformer with the customers using the transformer. This resulted in allocating approximately 233,000 transformers to the different classes by type and size. Roughly 85% of the line transformers are used by a single class and thus were directly assigned. The remaining 15% were assigned to each class based upon the class' relative contribution to the transformer's peak load. The transformers were priced at current costs, including installation, to determine each class' contribution to embedded line transformer costs (FERC account 368).

Q. How were distribution line costs allocated?

A. The Company used its customer and distribution feeder databases to associate each of our customers with over 1,100 feeders in the company. NCP load factors were used for each customer class to determine each class' contribution to each feeder's peak load. Each class' contribution to peak was multiplied by the number of overhead / underground miles on the feeder. These allocators were then summed across all the feeders to develop the overhead and underground distribution line cost allocators. The overhead allocators were applied to FERC accounts 364 and 365 and the underground allocators were applied to FERC accounts 366 and 367. The method recognizes that the cost of the distribution feeder investment is a function of both load and line miles.

Q. Why should miles of distribution line be incorporated into the cost allocation?

A. The cost of building overhead or underground distribution lines is primarily a function of distance, with cost adjustments for capacity. Cost is driven by the number of miles of trench excavated, miles of conductor required, number of poles installed, etc. There is an incremental cost for load, but it is relatively small since the Company uses only a few standard wire sizes for overhead and underground feeders and taps.

Q. Would you please describe how substation costs were allocated?

A. Yes, each customer class' contribution to the Company's substation's peak was calculated using average hourly consumption of each class divided by NCP load factors. The resulting percentage was multiplied by the substation's net plant balance expressed in 2003 dollars to develop the substation cost allocations for FERC accounts 360-362.

Q. How were service lines allocated?

A. Service lines were allocated based on counts of customers who take service at secondary voltage. All underground services are allocated to the residential class since non-residential secondary voltage customers own their own services. Overhead services are allocated by counts of secondary voltage overhead service customers by class.

E. General & Administrative Cost and Other Cost Allocation Factors

Q. How were A&G costs allocated?

A. These costs were allocated consistently with the methodology approved by the Commission in the 1992 rate design case. The bulk of A&G costs are assigned on adjusted production, transmission, distribution, and customer costs. Property insurance was allocated on plant, and pensions and employee insurance follow the allocation of salary and wages.

Q. What other direct cost allocators were used in the cost of service study?

A. The Company reviewed historical experience with late payment and assigned the costs to each class. Other miscellaneous revenues associated with NSF checks and reconnects are allocated to each class based upon a historical analysis of revenues received.

Q. Did you prepare a cost of service study in accordance with the Commission-approved methodology?

A. Yes, this is provided as Exhibit No. ____(CEP-9).

Q: What Exhibits are you sponsoring in this proceeding?

A: I am sponsoring the following Exhibits:

- **Exhibit No. ___ (CEP-2)** Professional Qualifications
- **Exhibit No. ___ (CEP-3)** Summary of Natural Gas Cost Study Results
- **Exhibit No. ___ (CEP-4)** Detailed Natural Gas Cost Study Results
- **Exhibit No. ___ (CEP-5)** Class Load and Service Characteristics of the Company's Natural Gas Customers
- **Exhibit No. ___ (CEP-6)** Reconciliation of Total Booked Revenues
- **Exhibit No. ___ (CEP-7)** Customer Classified Natural Gas Revenue Requirement

- **Exhibit No. ___ (CEP-8)** Electric Cost Study Results – Company Proposed
- **Exhibit No. ___ (CEP-9)** Electric Cost Study Results – Commission Basis
- **Exhibit No. ___ (CEP-10)** Peak Credit Calculation

Q: Does this conclude your direct testimony?

A: Yes.

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