EXHIBIT NO. T-_____(CEL-7)
DOCKET NOS. UE-920433, UE-920499 and UE-921262
WITNESS: C.E. LYNCH

BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

COMPLAINANT

VS.

PUGET SOUND POWER & LIGHT COMPANY

RESPONDENT

REBUTTAL TESTIMONY

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION
No. UE-920433; -920499; -921262 Ex. 76✓

PUGET SOUND POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF COLLEEN E. LYNCH

Q. Please state your name, business address and position with Puget Sound Power & Light Company.

A. My name is Colleen E. Lynch, my business address is 411 108th Avenue N.E., Bellevue, Washington 98004 and I am Manager of Pricing.

Q. Did you present direct testimony in this proceeding?

A. Yes, I did.

SUMMARY OF TESTIMONY

Q. Would you please summarize your rebuttal testimony?

A. Yes. My rebuttal testimony responds to the various cost of service adjustments proposed by other parties. Initially, I show the results that would be produced under each party's proposal, and compare the various proposals with each other and with the Company's original cost of service proposal. I then discuss the Company's position on the major issues raised by the other parties' testimony, including the Company's recommendations regarding cost of service. Finally, I present the Company's revised cost of service study.

Q. Various parties have presented cost of service proposals, with the results being quite different when looking at individual customer classes. Isn't there one "correct" approach to cost of service?

A. We are hesitant to identify any study, including our own, as being the "correct" approach to cost of service. Cost of service studies are a product of philosophical approaches and assumptions about the most accurate ways to spread joint costs. Not surprisingly, the cost of service proposals presented by other parties to this proceeding yield results which are quite different when compared to each other. These results are somewhat predictable in that they tend to shift costs away from the sponsoring party's constituency and toward all other classes. The class increases proposed by the parties reflect this, as shown in Schedule 1 of Mr. Hoff's Exhibit No. ___ (DWH-10).

Our proposed cost of service study is a reasonable approximation of the relative relationship of each class when compared both to the system and to other classes. As in the past, the Company's results tend to be somewhere in the middle ground when compared to these other study results.

Q: Would you please summarize the major issues regarding cost of service in this case?

A. Yes. The major areas of debate on cost of service centered on the four issues identified below (with the Company's recommendations summarized below each issue):

Issue No. 1: The calculation of the peak credit method.

- The peak credit method should be based on one-half the capacity and fixed O&M costs of a combustion turbine.
- The fuel used for purposes of the analysis should be 100% diesel.
- An 80% capacity factor should be used for the combined cycle combustion turbine.

Issue No. 2: The method of classifying and allocating non-generation related transmission costs.

- Non-generation related transmission plant should be classified and allocated as being 100% demand related.

Issue No. 3: The method of classifying and allocating distribution related costs.

- For purposes of this proceeding, distribution costs should be allocated using the basic customer method.
- Absent decoupling, the minimum system method should be used to allocate distribution costs.
- Methods used for gas cost of service studies are not necessarily directly transportable to electric utilities.
- The line extension credit based on revenues (kwh sales) is not indicative of the need, decision, or requirement to build electric distribution plant.

Issue No. 4: The determination of demand and energy allocation factors.

- For purposes of this proceeding, the coincident peak demand allocation factor should be based on the top 200 hours of peak demand.
- For purposes of this proceeding, the energy allocation factor should be adjusted to reflect the pro forma revenue temperature adjustment.
- Further adjustments to account for conservation benefits, temperature and normalization are appropriate but require further investigation prior to implementation.

Exhibit No. ___ (CEL-8) summarizes the parties' positions on these four issues.

COMPARISON OF RESULTS

Q. Have you prepared exhibits illustrating the various proposals presented by other parties?

A. Yes. I have prepared several exhibits which illustrate the effects of the various proposals on the class level cost of service. Schedule 1 of Exhibit No. ___ (CEL-9) compares the overall results under each party's cost of service proposal.

Q. What do the remaining schedules in Exhibit No. ___ (CEL-9) show?

A. These schedules illustrate each party's position with respect to the four issues identified above. Changes to the peak credit factor are shown in Schedule 2, changes to the classification and allocation of non-generation related transmission costs are shown in Schedule 3, changes to the classification and allocation of distribution costs are shown in Schedule 4, and Schedule 5 shows changes to the calculation of the demand and energy allocation factors. These exhibits are similar to those presented in my Exhibit No. 6 (CEL-5).

ANALYSIS OF SPECIFIC ISSUES

1. <u>The Calculation and Application of the Peak Credit Method</u>

Q. Please describe the points of contention regarding the calculation and application of the peak credit method.

A. The three main issues relating to the calculation of peak credit are (1) the fuel choice for the combustion turbine ("CT"), (2) the fixed costs associated with providing peaking capacity, and (3) the utilization rate or capacity factor to use for the combined cycle combustion turbine ("CCCT").

Because the Company does not have firm gas contracts, we propose that the CT fuel be based on the cost of #2 diesel fuel. We also propose using one-half of the fixed cost of the CT, recognizing the other hydro-firming benefits of the

CT. For the baseload plant, the CCCT , we have used a capacity factor of 80%. This recognizes that from a planning perspective, this plant is being brought on line to provide ongoing, year-round energy to our customers.

Q. Why has the Company used oil as the fuel choice for the CT even though only natural gas was used at these facilities during the test period?

A. It has been the Company's experience that natural gas is not available on a firm basis during periods of extreme peak. Our use of oil for fuel is based on our expectations regarding gas availability given our experience at such times. It should be emphasized that the test period did not include an extreme peak period. In contrast, during our last extreme peak, the 1990 "Arctic Express," our CTs ran and were burning oil because our natural gas contracts were interrupted. Additionally, gas was not available during the more recent peak periods in 1992.

Q. Why was only one-half of the fixed costs considered when computing the peak credit factor?

A. Combustion turbine units provide other benefits in addition to peaking. As Mr. Schoenbeck stated in his testimony at page 7, lines 11-13, the foundation of the peak credit theory is to separate these joint uses by determining the cost of supplying pure peak capacity. Given that objective, it is inappropriate to attribute 100% of the CT fixed costs to capacity when these units obviously provide other benefits. Mr. Schoenbeck recognizes this to be true for any resource (page 7, line 8). This concept is confirmed by the market price for capacity which, when adjusted for the long term, is roughly equal to one-half of the total installed cost of a CT on a kW basis. For these reasons, we have used one-half of the fixed cost of a CT as the proxy for the cost of pure capacity in the peak credit calculation.

Q. Why has the Company used an 80% capacity factor, rather than an expected utilization factor, for the assumed operation of the CCCT?

A. This makes the analysis consistent with other planning assumptions. The peak credit method is designed to reflect the **planning** criteria of the Company, and use of a capacity factor rather than expected utilization is consistent with this approach. Moreover, this is consistent with the calculation used in our 1992-93 Integrated Resource Plan (page 53, Table 5-3). An 80% capacity factor for the CCCT was also used in our 1993 study of avoided cost used in the Schedule 83 filing. Inasmuch as the peak credit method is designed to reflect the economic trade-off of the various resource types or supply options available to the Company, consistent assumptions should be used.

2. <u>Method of Classifying and Allocating Non-Generation Related Transmission Costs</u>

Q. Please describe the issues regarding classification and allocation of non-generation related transmission costs.

A. The Company proposed that non-generation related transmission costs be classified and allocated as being 100% demand related. This approach recognizes the reason for which the investment was made. SWAP, WICFUR and BOMA support the Company's proposal in this regard. Other parties maintained that all transmission should be allocated using the peak credit method.

Q. Throughout the rate design proceedings, parties have pointed to the NARUC Cost Allocation Manual as being an important reference regarding cost of service issues. What does the Manual say about the treatment of transmission plant?

A. The NARUC Cost Allocation Manual identifies several allocation methods associated with transmission costs in embedded cost of service studies, some of which treat these costs as being 100% demand-related. In addition, the Commission has held--and the collaborative group agreed--that embedded cost of service should be forward looking. Staff witness Sorrells points this out in her direct testimony (at page 2, lines 6-7). The Manual states at page 128 that for purposes of a forward-looking marginal cost study, investment in transmission system is generally assumed to be driven by increments in system peak load. Our treatment of non-generation related costs is consistent with that premise, as it is reflective of marginal cost and forward looking concepts.

3. Method of Classifying and Allocating Distribution Related Costs

Q. Please explain the difference in the parties' views on the treatment of distribution-related costs.

A. In the Company's proposal, we used the basic customer method to classify and allocate distribution plant "primarily in the interests of promoting consensus" (Exhibit T-2, page 19, line 4.) Other than the Company, two parties favor the minimum system, two parties favor the basic customer and two parties remain silent on the issue.

Q. Why does the Company favor the basic customer method over the minimum system approach it formerly advocated?

A. Under decoupling and in consideration of the collaborative effort, the Company is proposing that the basic customer method be used. If decoupling was abandoned and the collaborative effort ignored, the Company would propose the minimum system method. We prefer the minimum system method as an analytical evaluation tool. The Company has consistently taken the position that the minimum system method was the more appropriate method to use when evaluating cost of service. We continue to believe in the merit of the approach. In fact, we recently developed a new approach to modeling the minimum system as I stated during my deposition (Exhibit 17, page 24, lines 16-25). The Company uses the new minimum system analysis when evaluating marginal cost issues.

Q. Where does the industry stand on use of the minimum system method for classifying distribution costs?

A. The method is widely used. There are two ready sources for investigating the electric utility industry's practices regarding this issue. One is in the form of surveys of both companies and regulators. The results of the surveys indicate that the minimum system type approach (where facilities in addition to the meter and service are deemed to have a customer component to them) is a fairly common method. (See the Edison Electric Institute 1980s survey and the 1989 survey performed by Economic and Engineering Services, Inc., referred to at page 13 of BOMA witness Saleba's testimony.) The second source is utility cost allocation guidebooks, such as the NARUC Electric Utility Cost Allocation Manual which offers the minimum system method as an acceptable method to use to apportion distribution costs between demand and customer.

Q. What are the effects of using the minimum system approach?

A. The effects are shown in Schedule 4 of Exhibit No. ___ (CEL-9). This shows two scenarios showing the effects of using a minimum system approach to classify and allocate distribution costs. The scenario entitled "Minimum System - Traditional" reflects the use of the Company's traditional minimum system study and is an update to that presented in my Exhibit No. 6 (CEL-5), page 5, lines 3-4. This is the method I referred to during my deposition (Exhibit 17, page 24, lines 7-15). The scenario entitled "Minimum System - Alternate" reflects the use of the study I referred to at page 24, lines 16-25 of my deposition (Exhibit 17). This study is the basis for the Company's analysis of marginal distribution costs.

Q. Do the Company's current line extension policies provide an indication of cost responsibility at the distribution level, as suggested by Mr. Lazar?

A. Definitely not. Several parties have pointed to the current method of computing line extension allowances and erroneously concluded that the investment in distribution plant is causally related to the amount of revenue anticipated to be recovered from the customer. Our obligation to provide service at the customer's request, however, precludes us from making the determination that a benchmark of revenues must be satisfied before a customer can be connected to the system. Our line extension policies simply reflect a reasonable method of allocating those line extension expenses between the new customer and the general body of customers. They should not be interpreted as any indication of cost causation.

Furthermore, Staff and Public Counsel erroneously assume that since the majority of our revenue are recovered through an energy charge, the distribution system was built to provide energy. The fact that the majority of our revenue is recovered via an energy charge is merely a byproduct of traditional ratemaking practices as well as billing and metering practices, and not an indicator of cost responsibility at the distribution level.

Q. Mr. Lazar's testimony refers to the application of gas cost of service principles. Should Commission approved cost of service methods for gas cost of service be applied to an electric utility?

A. Not directly. There is some commonality between the two industries in their approaches to cost of service. While there are similarities in the analysis of cost of service between all regulated industries, a major difference between electric utilities and gas utilities is the obligation of an electric utility to provide service to all customers who request it. In addition, I would be reluctant to say that the electric utility is the same as any of the other regulated industries due to differences in technology and end products.

4. <u>Determination of the Demand and Energy Allocation Factors</u>

Q. How are the coincident peak demand and energy allocation factors calculated in the Company's proposed cost of service study?

A. The coincident peak demand allocation factors are based on each class's contribution to the system's top 200 coincident peak hours. The energy allocation factors are based on each class's annual kWh consumption.

Q. What is the impact of these demand and energy allocation factors?

A. These two sets of allocation factors are material to the ultimate cost responsibility attributed to any one class. Roughly 75% of total operation and maintenance expense is directly or primarily allocated using energy and demand factors. Approximately 45% of total electric plant is assigned to classes using these same factors. In addition to these primary allocations, a significant portion of the secondary allocations are also based on results of using these factors.

Q. Please describe the issue regarding the determination of the demand allocation factors.

A. In general, the issue is the number of hours to include in the calculation of the demand allocation factors. In some proposals, these arguments led into other issues such as the seasonality of loads, normalization for temperature and the treatment of the imputed benefits of conservation.

Q. Please describe the test period in terms of peak load and average temperature.

A. As Mr. Schoenbeck describes, the peak loads in the test period were significantly lower than both the Company's actual all time system peak of 4615 MW set in December 1990 and the extreme peaks used in our projection of loads/resource requirement. The temperature for the period tended to be somewhat warmer than average as evidenced by our proposed positive temperature adjustment.

Q. **What problems does this cause in calculating the coincident demand allocation factors?**

A. The resulting demand allocations tend to be dampened for classes which drive the system peak, such as residential customers. The more constant year-round users, such as high voltage, tend to be penalized in this circumstance.

Q. **If, as Mr. Schoenbeck contends, the test period was much warmer than average and the loads much lower and flatter than average, should there be an adjustment to the demand allocation factors?**

A. Yes, an adjustment may be appropriate. But the Company does not propose adoption of either of the approaches recommended by Mr. Schoenbeck, i.e., his proposals to base the factors on loads in excess of 95% of the peak or to make class level temperature adjustments.

Q. **Wouldn't Mr. Schoenbeck's proposed method of looking at loads in excess of 95% of the peak mitigate this problem?**

A. This method would do a better job at capturing the peak contributors. This is due simply to the fact that reducing the number of hours in the averaging process tends to minimize or camouflage the true effects of peak users to the detriment of more constant or even users such as the high voltage class. However, under situations when system and class loads were quite flat (on average) the results would not be significantly different.

Q. Is the Company recommending this method?

A. No. The Company is recommending that the demand allocators be based on 200 hours. The objective of our cost of service proposal is to reflect the Company's planning process, which is done so using the 200 hours.

Q. Is there any merit to Mr. Schoenbeck's other proposal to adjust the demand allocation factors for weather/temperature?

A. Yes. Class level temperature adjustments to normal temperature would be appropriate if the necessary data exist. However, the data are not available. To make such an adjustment now would require making assumptions as to the class level adjustments and may cause additional errors in the estimate rather than improve the estimate.

Q. What about the proposal to adjust the demand allocation factor for the imputed benefits of conservation?

A. Yes. Assuming the data exist, class level adjustments to reflect the imputed benefits of conservation would be appropriate. This would be another step toward treating conservation in the same manner as supply side resources. However, the data are not available.

Q. What key assumptions would need to be resolved?

A. The assumptions used in imputing conservation benefits would need to address a number of points, including those identified below. It should be noted that although this subject and these points were raised during the collaborative group deliberations, the discussion was very limited and there was no investigation or resolution of these items:

- Free riders
- Load retention vs. conservation
- Customer contributions
- Verification of life/continued participation
- Cream skimming

Q. Is the method proposed by Mr. Schoenbeck a reasonable approach?

A. No. Although the concept is valid, Mr. Schoenbeck's proposal does not consider the above points. In addition, his method relies on a simplistic allocation of the Company's estimated MW and aMW reductions by conservation program to the classes of service utilized in cost of service.

Q. What are the other parties' views on the issue of the determination of the energy allocation factor?

A. In general, the issue is centered on the seasonality of loads. This issue also leads into similar debates as to normalization for temperature and the treatment of the imputed benefits of conservation.

Q. For cost of service purposes, how does the Company's proposal treat the temperature adjustment included in the pro forma adjustment?

A. Under the Company's original proposal, the revenue benefit associated with the temperature adjustment is assigned to the residential class. As shown on Exhibit 558 (JHS-2), p. 204, the adjustment is based on kWhs and the last step of the residential rate. However, there was no corresponding adjustment to the energy allocation factors in the cost of service. Our revised cost of service study, included as Exhibit No. ___ (CEL-10), includes an adjustment to the residential energy allocation factor in recognition of this temperature adjustment.

Q. Is the residential class the only temperature sensitive class load?

A. No. Several other classes of service, such as commercial establishments with electric space heat, may also have temperature sensitive aspects to their energy and demand. However, data are not sufficient at this time to go beyond the current treatment of the temperature adjustment.

Q. Under the Company's cost of service, should the energy factor be adjusted for seasonal cost differences in energy as proposed by Mr. Carter?

A. No. The focus of the proposed cost of service methodology is not on the seasonal cost differentials. The method is not intended to present seasonally differentiated results, although inferences can be drawn from the study results based on the seasonal attributes of certain allocation factors.

If the cost of service objective is to determine cost of service by season by class, many other adjustments to the method would be necessary. The simplistic adjustment proposed by Mr. Carter is not adequate.

Q. What is the Company's overall proposal regarding the determination of demand and energy factors?

A. The Company recommends that the Commission accept the revision of the residential energy allocation factor prepared by the Company and presented in Exhibit No. ___ (CEL-10), the revised cost of service study. Subsequently, the Company will begin an investigation into the major issue of demand and energy allocation factors. The Company will provide the Commission with study results and ultimately a recommended solution as part of the next general rate filing, assuming the current three-year cycle. This extended period of time is necessary to perform the analysis and collect the data anticipated to be required.

THE COMPANY'S REVISED COST OF SERVICE PROPOSAL

Q. What is the Company's proposal regarding cost of service?

A. For purposes of this proceeding, the Company recommends that the Commission approve all of the methods and concepts used by the Company in Exhibit No. ___ (CEL-10).

Q. Will the Company be recasting the cost of service analysis prior to implementing rates resulting from the Order in the general rate proceeding?

A. The Company intends to recast the cost of service study and file that study with the Company's rebuttal testimony in the general rate proceeding. This will allow parties to see the effects on cost of service of any changes the Company makes to its proposed revenue requirement at that time. It will also allow the Company to make any changes to the cost of service model which may be appropriate as a result of the rebuttal phase of the rate design case.

Q. Does this conclude your rebuttal testimony, Ms. Lynch?

A. Yes, it does.