PUGET POWER

July 9, 1993

VIA MESSENGER

Mr. Paul Curl, Secretary
Washington Utilities and
Transportation Commission
P. O. Box 9022
Olympia, Washington 98504-8002

RE: Docket No. UE-920499
Puget Sound Power & Light Company
Rate Design

Dear Mr. Curl:

Enclosed for filing in the above matter is an original and nineteen (19) copies of the Brief of the Company.

Sincerely,

Robert J. Kalina

Robert J. Kalina

RJK:bk

Enclosure

cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Brief of the Company upon all parties of record, as identified below, by transmitting a copy thereof, properly addressed with postage prepaid, either through the United States mail or by overnight courier, or by personal delivery of a copy thereof upon such party.

Dated at Bellevue, Washington this 9th day of July, 1993.

Robert J. Kalina

Public Counsel
Charles F. Adams
Assistant Attorney General
Public Counsel Division
900 Fourth Avenue, Suite 2000
Seattle, WA 98164

SWAP
Carol S. Arnold
Preston Thorgrimson Shidler
Gates & Ellis
5000 Columbia Center
701 Fifth Avenue
Seattle, WA 98104-7078

BOMA
John A. Cameron, Jr.
Ater, Wynne, Hewitt,
Dodson, & Skerritt
1201 3rd Avenue, Suite 2850
Seattle, WA 98101-3000

Federal Executive Agencies
Norman J. Furuta
Office of General Counsel
Department of the Navy
900 Commodore Drive
P.O. Box 727
San Bruno, CA 94066

Commission Staff
Donald T. Trotter
Assistant Attorney General
Heritage Plaza Building
1400 S. Evergreen Park Drive S.W.
Olympia, WA 98504-8002

WICFUR
Mark P. Trinchero
Davis Wright Tremaine
2300 First Interstate Tower
Portland, OR 97201-5682

Admin. Law Judge
Alice L. Haenle
Administrative Law Judge
3rd Floor, FS-34
2420 Bristrol Ct. S.W. Bldg. E
Olympia, WA 98504-2489

DOCKET NOS. UE-920433,
UE-920499, and UE-921262

**BEFORE THE
WASHINGTON UTILITIES & TRANSPORTATION
COMMISSION**

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

COMPLAINANT

VS.

PUGET SOUND POWER & LIGHT COMPANY

RESPONDENT

**BRIEF OF RESPONDENT PUGET SOUND POWER & LIGHT COMPANY
RATE DESIGN ISSUES**

PERKINS COIE
James M. Van Nostrand
Steven C. Marshall
Suite 1800, One Bellevue Center
411 - 108th Avenue, N.E.
Bellevue, WA 98004
(206) 453-6980

Attorneys for Puget Sound
Power & Light Company

DATED: July 9, 1993

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I. INTRODUCTION

This proceeding was commenced in response to the Commission's direction in Docket Nos. UE-901183-T and UE-901184-P (the "Decoupling Proceeding"), where the Commission ordered the Company to submit a rate design filing that would allow a review of rate spread, rate design and cost allocation issues. (Third Supplemental Order, p. 24.) Following the commencement of this proceeding in April 1992, the Company submitted a general rate case filing in Docket No. UE-921262 (the "General Rate Case"), which was consolidated with this rate design proceeding. Notwithstanding this consolidation, the hearings on these rate design issues have been conducted on a separate schedule.

II. OVERVIEW OF PROCEEDING

A. Procedural Background

This case represents another important step on the path of regulatory changes initiated by the Commission to facilitate the implementation of integrated resource planning. These changes include the adoption of the Commission's rule requiring periodic integrated resource plans; the introduction of competitive bidding as a means of acquiring new resources; and a Notice of Inquiry ("NOI") to eliminate barriers to least-cost planning, which ultimately resulted in the Commission's approval of a Periodic Rate Adjustment Mechanism ("PRAM") for the Company. One feature of the PRAM is the "decoupling" of the Company's allowed revenues from kilowatt-hours, which introduces a new ingredient into the equilibrium of competing issues associated with rate design. It is in light of this changed regulatory environment that rate design issues are examined anew.

Apart from the changed environment arising from decoupling, this case is unique in other respects as well. First, rate design and cost of service issues were explored in a less contentious manner than in the past. The Commission's order in the Decoupling Proceeding, which said "the Commission staff and other parties are encouraged to work with the Company" in the discussion of rate design issues, set a very important tone for the preparation of this filing. (Third Supplemental Order, p. 24) In response to this encouragement by the Commission, the Company formed a Rate Design Collaborative Group (the "Collaborative Group") to focus specifically on rate design issues.[1] The Collaborative Group was able to reach consensus on a number of issues which were incorporated into the Company's filing.[2] In addition, the Customer Rate Design Task Force (the "Task Force") was developed along the lines of the Company's successful consumer panel program. The Task Force, composed primarily of residential customers, also focused on rate design issues, and worked with the Collaborative Group.[3]

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[1]The Collaborative Group was made up of intervenors in past rate cases, the Commission staff, and other interested experts who have not typically been involved in past rate proceedings.

[2]Exhibit 11 in this proceeding is the final report of the Collaborative Group.

[3]Exhibit 10 in this proceeding sets forth the final report and recommendations from the Task Force.

Second, a separate proceeding devoted to rate design and cost of service issues has allowed a more complete examination of these matters. As a result, the parties were able to reach agreement on a number of issues, thereby reducing the number of contested issues and allowing a more thorough discussion of these remaining issues. In this regard, it should be noted that substantial use was made of the Company's cost of service model, which enabled side-by-side comparison of the parties' proposals. To facilitate this use, the Company went so far as to provide training sessions for the Commission and the parties on the use of its cost of service model.

It is hoped that the extensive attention devoted by the parties to these issues will result in a Commission order on rate design and cost of service being issued prior to the order in the General Rate Case.[4] In the Company's view, this order would address issues on two levels. First, the order would include direction on general concepts discussed in the case, including the remaining contested issues on cost of service and rate spread. Second, the order would contain the resolution of issues specific to individual rates (such as the block structure for residential rates (Schedule 7), the creation of new schedules for general service customers, and adoption of the Company's proposed experimental rates,) and the setting of target parity ratios to be used in the General Rate Case. It is obvious that all rate

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[4]As discussed in Mr. Hoff's testimony, issuance of the rate design order on or about August 16 would allow sufficient time to notify affected customers and implement necessary billing changes. Ex. T-83, p. 2.

design issues cannot be resolved in the rate design order; issues involving the exact level of rates, for example, must await the determination of the revenue requirement in the General Rate Case.

B. Objectives in Designing Rates

This proceeding presents an opportunity to pursue a number of key objectives, including the following:

- Facilitate implementation of integrated resource planning.
- Send a stronger and more accurate price signal to our customers regarding the costs of producing energy, and thus rely on economic efficiency and market forces to encourage efficient energy usage.
- Provide guidance on the calculation of cost of service.

Ex. T-1, pp. 4-5.

There are many, sometimes conflicting, objectives in designing rates. The Commission in its order in Docket No. U-89-2688-T, the Company's 1989 rate proceeding (the "1989 Rate Case"), identified the following factors considered important in the design and spread of rates. They are:

- acceptability of rate design to customers,
- elasticity of demand,
- perceptions of equity and fairness,
- rate stability over time, and
- overall economic circumstances within the region.

Third Supplemental Order, p. 73.

These objectives were, to some extent, echoed by the participants in the collaborative process. The Rate Design Task Force, for its part, stressed **parity.** The Task Force concluded that "each user should pay a fair share of electrical power based on a WUTC approved cost of service to the user's classification". (**See** Rate Spread Recommendation A of the Task Force, Exhibit 10, p. 12.) This objective is closely related to the equity and fairness factor identified by the Commission, as noted above. The Task Force also stressed **gradualism**, or the notion that significant policy changes should be implemented gradually over time to avoid disruptions. (**See** Rate Spread Recommendation C, Exhibit 10, p. 13.) This corresponds with the goal of rate stability over time, as set forth in the factors identified by the Commission above. Issues regarding elasticity of demand and the basis for elasticity adjustments were referred to the General Rate Case and are discussed by Mr. Hoff in his testimony in that proceeding.

III. OVERVIEW OF PARTIES' COST OF SERVICE AND RATE SPREAD PROPOSALS

The starting point in the analysis of rate design issues is the cost of service study. The purpose of performing a cost of service study is to attribute costs to different categories of customers (classes) based on how those customers caused costs to be incurred. Ex. T-2, p. 2. The results of this process are then used for a number of purposes, including the basis for recommendations for the allocation of the revenue requirement across customer classes (or rate spread) and the setting of demand, energy and customer charges within customer classes.

Although there is no single, "correct" approach to cost of service, the Company has offered a cost of service study which is a reasonable approximation of the relative relationship of each class when compared both to the system and to other classes.[5] The Company's results tend to be somewhere in the middle ground when compared to the approaches advanced by other parties.

The Company recommends that its cost of service results should be the basis for movement toward parity.[6] More specifically, the Company recommends that the movement should eliminate approximately one-third of the disparity for retail jurisdictional customers. Figure 1 below graphically displays the rate increases which would result under the Company's and the other parties' recommendations on cost of service and rate spread. It is interesting to note that the recommended class rate increases range from a low of 2.6% (Schedule 25, WICFUR) to a high of 41.8% (Schedules 46 and 49, Public Counsel).[7]

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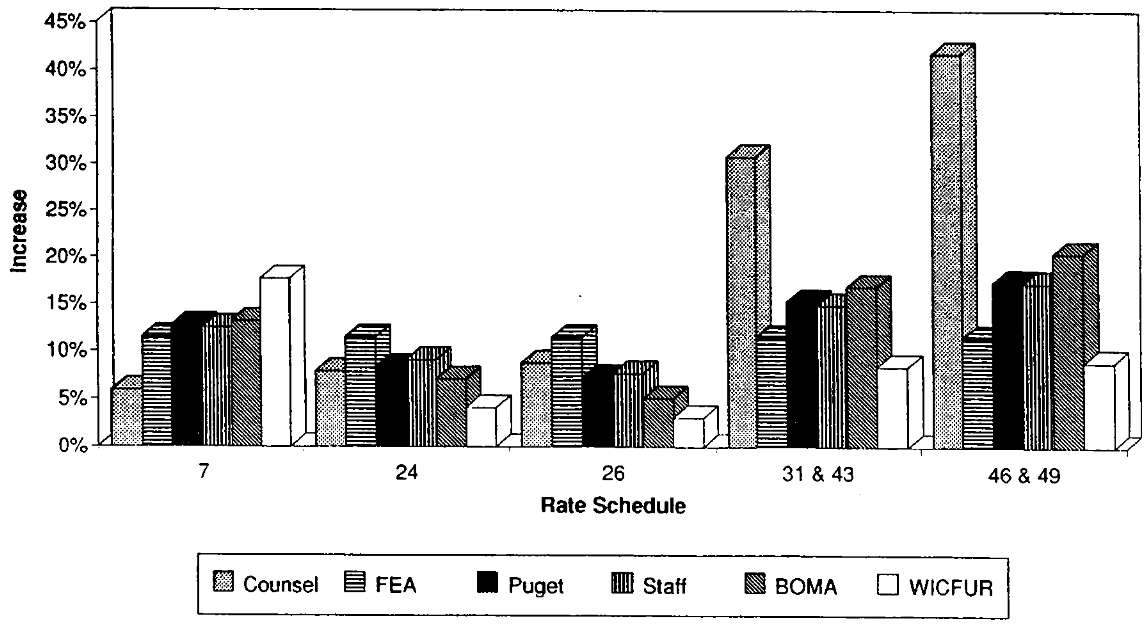
[5]Attachment A hereto is a summary of the process of performing a cost of service study, as well as a brief description of the Company's cost of service study. The source of Attachment A is Ex. T-2, pp. 1-30.

[6]Parity is the relationship between what customers should pay according to a cost of service analysis and what the customers are actually paying. A parity relationship of 90%, for example, means that a particular customer class is paying only 90% of the costs allocated to it. This also means that the customer class is being subsidized by other customers. If one class of customers is below parity, and thus enjoying a subsidy, another class must be above parity and paying the subsidy, because parity based on the allowed revenue requirement must, by definition, average 100%.

[7]Based on the General Rate Case request of $117 million.

Figure 1

Comparison of Proposals to Allocate Rate Increase



Source: Exhibit 84.

IV. COST OF SERVICE

A. Summary of Key Cost of Service Recommendations

The Company's key cost of service recommendations are summarized as follows:

- All parties should use the same model framework for making cost of service presentations.

- The peak credit method should be used to classify production plant between demand and energy.

- Forward-looking relationships should be used in the embedded cost of service study to better signal costs to customers.

- Nongeneration-related transmission plant should be classified and allocated as 100% demand-related.

- Conservation costs should be treated as a resource cost.

- Cost of service, as it is approved by the Commission in this case, should be a major factor, along with parity guidelines, in rate spread considerations.

- The basic customer concept should be the basis for classifying distribution plant between demand and customer, in a decoupled environment.

- The fully distributed customer-related cost of service resulting from applying the basic customer method should be recovered through a basic charge for those tariffs with a basic charge component.

It should be noted that many of these concepts are endorsed by either the Task Force or the Collaborative Group, or both.

B. Contested Issues Regarding Cost of Service

There was little disagreement regarding most elements of cost of service. The major areas of debate on cost of service were primarily limited to four issues, as identified below:

- The calculation of the peak credit method.

- The method of classifying and allocating non-generation related transmission costs.

- The method of classifying and allocating distribution related costs.

- The determination of demand and energy allocation factors.

1. The Calculation and Application of the Peak Credit Method

Summary of Argument:

- The peak credit method should be based on one-half the capital and fixed O&M costs of a combustion turbine.

- The combustion turbine fuel used for purposes of the analysis should be 100% diesel.

- An 80% capacity factor should be used for the combined cycle combustion turbine.

There was general agreement among the parties that the peak credit method should be used to classify energy and demand costs for production plant.[8] The three main issues relating to the calculation of peak credit are (1) the fixed costs associated with providing peaking capacity, (2) the fuel choice for the combustion turbine ("CT"), and (3) the utilization rate or capacity factor to use for the combined cycle combustion turbine ("CCCT").

Only one-half of the fixed costs are considered when computing the peak credit factor because combustion turbine units provide other benefits in addition to peaking. (Ex. T-2, p. 14; Ex. T-8, p. 11) As WICFUR witness Schoenbeck stated in his testimony (Ex. T-73) 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. The Company's Integrated Resource Plan confirms that the combustion turbines were installed for purposes other than serving peak load needs:

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[8]The Commission has previously adopted the peak credit method for classifying energy and demand costs for the Washington Water Power Company (Cause No. U-82-10, Second Supplemental Order, p. 37; for Pacific Power and Light Company (Cause No. U-82-12, Second Supplemental Order, p. 34; and for the Company (Cause No. U-82-38, Third Supplemental Order, p. 30. Navy witness Knobloch's testimony that the peak credit is not an accepted method (Ex. T-40, pp. 2, 4 and 6) is in complete disregard of the Commission's precedent on this issue.

> Puget Power installed three pairs of combustion turbine units (CTs) in the early 1980s to meet rapidly increasing peak load needs and **for energy production during periods of low streamflows.** . . . Puget Power's combustion turbines have been used both for peaking and **for short-term energy production** over the past several years . . .

1992-93 Integrated Resource Plan, Appendix C, page 6 (emphasis added). This approach 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. (Ex. T-8, p. 12) For these reasons, one-half of the fixed cost of a CT is used as the proxy for the cost of pure capacity in the peak credit calculation.

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. (Ex. T-76, p. 6) It has been the Company's experience that natural gas is not available on a firm basis during periods of extreme peak. Use of oil for fuel is based on the Company's expectations regarding gas availability given its experience at such times. It should be emphasized that the test period did not include an extreme peak period. In contrast, during the Company's last extreme peak, the 1990 "Arctic Express," its CTs ran and were burning oil because the natural gas contracts were interrupted. Additionally, gas was not available during the more recent peak periods in 1992. (Ex. T-76, p. 6)

The Company has used an 80% capacity factor, rather than an expected utilization factor, for the assumed operation of the CCCT to make the analysis consistent with other planning assumptions. (Ex. T-76, p. 7) 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 the Company's 1992-93 Integrated Resource Plan (Ex. 23, p. 53, Table 5-3). An 80% capacity factor for the CCCT was also used in the 1993 study of avoided cost used in the Schedule 83 filing. (Ex. T-76, p. 7) 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. Method of Classifying and Allocating Non-Generation Related Transmission Costs

Summary of Argument:

- Non-generation related transmission plant should be classified and allocated as 100% demand related. This treatment recognizes forward-looking relationships and, more specifically, that the Company incurs transmission plant expenditures primarily in response to growth in system demand.

The Company proposed that non-generation related transmission costs be classified and allocated as 100% demand related. This approach recognizes the reason for which the investment was made. The primary design consideration used in the planning and construction of the transmission network (nongeneration-related transmission) is the peak load the facilities must carry. (Ex. T-2, p. 17; see also Appendix F, pp. F1-F14 of 1992-93 Integrated Resource Plan (Ex. 23)) 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.

The NARUC Cost Allocation Manual, an important reference regarding cost of service issues, 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. (Ex. T-33, p. 2) 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. The Company's 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

Summary of Argument:

- 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.

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

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 prefer the minimum system method. The Company has consistently taken the position that the minimum system method is more appropriate to use when evaluating cost of service. The Company continues to believe in the merit of the approach and, in fact, recently developed a new approach to modeling the minimum system. The Company uses the new minimum system analysis when evaluating marginal cost issues.[9]

Another approach, suggested by Public Counsel, is to allocate distribution costs using gas cost of service principles. In the Company's view, Commission-approved cost of service

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[9]It should be noted that the minimum system method for classifying distribution costs 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 (Ex. T-54).) 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.

methods for gas cost of service should not be applied to an electric utility. While there are similarities in the analysis of cost of service between all regulated industries, the differences are so significant that the cost of service principles are not easily transferable. Differences in technology and end products, for example, make the electric utility incomparable in many respects to any of the other regulated industries. (Ex. T-76, p. 13) On this point, BOMA witness Saleba stated the following:

> As a general premise, a prudent cost allocation study should follow cost causation. Cost causation behind a natural gas system and an electric system are markedly different . . . . There are so many planning and operational differences between a gas utility and an electric utility it's hard to imagine that the same type of a classification allocation scheme would apply to both utilities.

Tr. at 1709.[10]

On a related issue, Public Counsel witness Lazar suggest that the Company's current line extension policies provide an indication of cost responsibility at the distribution level. (Ex. T-43, p. 19) The Company's line extension policies simply reflect a reasonable method of allocating line extension expenses between new customers and the general body of customers. They

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[10] With regard to this issue generally, the Company in Bench Request No. 7 was asked to perform a cost of service analysis using Public Counsel's stated assumptions assertedly reflecting the treatment of distribution plant in natural gas cost of service studies. Although the Company's response, included in Exhibit 82, reflects the instructions given by Public Counsel, the Company does not agree that this approach is valid or appropriate, for many of the same reasons as expressed by WICFUR in its comments regarding the response to Bench Request No. 7.

should not be interpreted as any indication of cost causation. (Ex. T-76, p. 12)

4. Determination of the Demand and Energy Allocation Factors

Summary of Argument:

- The coincident peak demand allocation factor should be based on the top 200 hours of peak demand.
- The energy allocation factor should be adjusted to reflect the pro forma revenue temperature adjustment. This adjustment was included in the Company's revised cost of service study.
- Further adjustments to account for conservation benefits, temperature and normalization are appropriate but require further investigation prior to implementation.

The coincident peak demand allocation factors in the Company's cost of service study 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 temperature-adjusted kWh consumption. (Ex. T-76, p. 18)

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.

a. Demand Allocation Factors

The issue regarding the determination of the demand allocation factors concerns, among other things, the number of hours to include in the calculation of the demand allocation factors. The Company uses 200 hours because it represents the annual number of hours of operation for the combustion turbines reflected or incorporated in the Company's planning models. In the Company's view, using 200 hours better matches the allocation factor with the planning criteria actually used by the Company. (Exhibit T-2, p. 27.) In some intervenors' 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.

WICFUR witness Schoenbeck proposed three modifications to the demand allocation factors, all of which should be rejected. First, with respect to the number of hours, Mr. Schoenbeck proposes to look at loads in excess of 95% of peak rather than during the 200 hours proposed by the Company. This approach reduces the number of hours considered from 200 to 3. (Tr. at 1808). Thus, this method might do a better job at capturing the peak contributors, 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. This method should be rejected, however, because it departs from the 200-hour figure used for planning purposes, and selection of the 95% figure appears to be arbitrary.

(Tr. at 1808) Moreover, it should be noted that under situations when system and class loads were quite flat (on average), the results under either method would not be significantly different.

Mr. Schoenbeck's second proposed modification to adjust the demand allocation factors for weather/temperature has some merit. 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.

Mr. Schoenbeck's third modification, relating to class-level adjustments to reflect the imputed benefits of conservation, might also be appropriate given sufficient data. This would be another step toward treating conservation in the same manner as supply side resources. However, the data are not available. The assumptions used in imputing conservation benefits would need to address a number of points.[11] 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. In addition, Mr. Schoenbeck's method relies on a simplistic allocation of the Company's estimated MW and aMW reductions by conservation program to the classes of service

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[11]The points include the following: free riders; load retention vs. conservation; customer contributions; verification of measure life/continued participation; and cream skimming.

utilized in cost of service. Also, as applied by Mr. Schoenbeck, the estimated MW reductions are based on an extreme peak situation and are not directly applicable to test period demand data.

b. Energy Allocation Factors

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.

The Company revised its cost of service study to include an adjustment to the residential energy allocation factor to normalize for temperature. The revised cost of service study, included as Exhibit No. 79, is consistent with the revenue calculation set forth in Exhibit 557 in the General Rate Case. It should be noted that the residential class is not the only temperature sensitive class load. 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.

The energy factor should not be adjusted for seasonal cost differences in energy as proposed by SWAP witness Carter. 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.

The Company proposes to investigate further the issues associated with demand and energy allocation factors raised in this proceeding. 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.

C. Other Issues

1. Calculation of Base Cost per Customer on an Individual Class Basis

The Commission in the Decoupling Proceeding directed the Company to identify Base and Resource Costs for each class. (Third Supplemental Order, p. 25.) This analysis is shown in Exhibit 80. For the reasons discussed in Mr. Hoff's and Ms. Lynch's rebuttal testimony in the General Rate Case, the Company opposes implementation of Base Cost per customer on a class-specific basis.

2. Adoption of Company's Cost of Service Model

One issue on which agreement was reached in the Collaborative Group was the benefits of using a single cost of service model to analyze cost of service and rate spread issues.

In this proceeding, a number of parties have used the Company's cost of service model to analyze their proposals. Staff, for its part, used the Company's cost of service model in preparing its response to Bench Request No. 6 (Ex. 81). And the Company has provided training sessions to enable parties to use its cost of service model. The Company urges the Commission to endorse use of the Company's cost of service model for analysis purposes in this and future proceedings.

D. Cost of Service Results

Summary 1 of Exhibit ___ (CEL-6) in the General Rate Case shows a class level income statement for each class considered in the cost study.[12] The bottom line of this report shows the realized rate of return for each class of customers based on the allocated operating expenses, income and rate base for that class. Summary 2, line 13 shows the resulting parity ratios under this cost of service study. These parity ratios are the basis for the Company's rate spread proposal.

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[12]Alternatively, the most current cost of service study in the rate design portion of the proceeding is Exhibit 78.

V. RATE SPREAD

A. The Company's Rate Spread Proposal

The following parity ratios are suggested by the Company's revised cost of service study (Exhibit ___ (CEL-6) in the General Rate Case):

	Secondary						
Residential	Sm.	Med.	Lg.	Primary	High Voltage	Lighting	Resale
96%	110%	117%	115%	93%	88%	136%	77%

Given these cost of service results, the Company proposes to allocate the revenue requirement across classes in a manner that moves toward 100% parity for all classes under the Commission's jurisdiction. (Ex. T-83, p. 5) This would be accomplished gradually by moving one-third of the distance to the target parity of 100%. The exception is the Firm Resale class, which would be moved to 100% parity.[13] This results in the following target parity ratios[14]:

	Secondary						
Residential	Sm.	Med.	Lg.	Primary	High Voltage	Lighting	Resale
97%	107%	111%	110%	95%	92%	124%	100%

These cost of service parity and target parity ratios should be used in connection with Schedule 7 of Exhibit 84.

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[13]The Firm Resale class is a wholesale class whose rates are not determined by the Commission.

[14]This recommended approach results in the following percentage changes to each class (based on the $103.5 million (10.3%) overall increase shown in the Company's General Rate Case rebuttal presentation): Residential (+11.9%); Secondary Voltage: Small (+7.7%), Medium (+4.5%), Large (+5.6%); Primary Voltage (+12.9%); High Voltage (+15.0%); Lighting (-1.8%); and Firm Resale (+33.3%).

Attachment B to this brief is a partially completed worksheet that could be used by the Commission to spread the increase in the General Rate Case across classes.

B. Rate Class Differentials Based on Risks and Growth Rates

Another issue related to rate spread is whether differences in either risk or growth rates should be considered in allocating the revenue requirement across classes. For the reasons discussed below, the Company opposes Public Counsel's proposal to consider rate class differentials based on risks and growth rates.

1. Risk-Based Differentials

The arguments of Public Counsel witness Lazar supporting class-differentiated rates of returns are flawed for four reasons. First, Mr. Lazar has offered no quantification of risk differentials. Second, he has offered no proof that financial markets view specific customer classes as more or less risky than other classes. Third, he has offered no proof that any perceived risks associated with serving individual customers are in any way correlated with the Company's definition of customer classes. Fourth, Mr. Lazar's conceptual application of risk is much too narrow. Most, if not all, risks perceived by investors are not confined to a specific customer class.

A number of risks are present in all customer classes, including risks related to stranded investment, requirements to provide standby service, and the under-recovery of Base and Resource costs. These risks are discussed in Mr. Hoff's rebuttal testimony (Ex. T-83) at pages 17-18. There are alternative rate designs that can mitigate these risks. However, consideration of these methods is premature in this proceeding, and is best left to future filings. Examples of risk-reducing rate designs are discussed in Mr. Hoff's rebuttal testimony (Ex. T-83) at page 19.

2. Differentials Based on Relative Growth Rates

Similarly, the Company opposes Public Counsel's suggestion that differences in growth rates should be considered in rate spread decisions. If growth is to be addressed through rate spread or rate design, it is best addressed at an individual customer level, not a class level. In this regard, the Company is not currently advocating growth charges at the customer level. The question of who should pay for growth is complex, with serious public policy ramifications. While growth is a cause of higher rates for the Company's customers, it also can mean job creation and other regional economic benefits. The issue of growth is more appropriately addressed through charges to individual customers, such as through energy rates that are based on marginal cost.

VI. RATE DESIGN PROPOSALS

The Company's filing includes rate design proposals in the following five general categories:

(1) residential rate design;

(2) secondary general service rate design;

(3) primary/high voltage rate design, including an experimental marginal cost based rate;

(4) various other rate design proposals, including interruptible rates for large power customers, a proposed power factor adjustment, an increase in the seasonal differential for energy charges, and a differential for seasonality in demand charges; and

(5) the allocation of PRAM revenues.

A. Residential Rates

1. Residential Rate Design

Summary of Argument:

- The change of schedule 7 to a two block rate is an important element to providing the efficient price signal.
- The setting of the block levels and prices must be done in the context of equity and efficiency. If the block is lowered to 600 kWh as Staff recommends and the Company revenue requirement is used, a preliminary analysis indicates that lights and appliance customers will get half the average rate increase and space heat customers will get twice the average increase.

The residential rate (Schedule 7) currently has a three-block inverted rate schedule, with the blocks set at 600 kWh and 1,000 kWh. The Company's original proposal in this proceeding included a monthly charge based upon the basic customer approach and a two block inverted energy rate, in accordance with the recommendations of the Collaborative Group. The tail block was set to give the marginal price signal based upon the power production cost of serving a residential water heat load, a twelve year time horizon.[15] The tail block was set at 500 kWh in

[15] The tail block is not actually set at the marginal cost, rather it is set so that the increment/decrement in the customer's total bill reflects marginal cost. The tail block rate is derived by subtracting the PRAM rate

the winter and 400 kWh in the summer in order to provide the marginal price signal to over 85% of the residential customers. (Ex. T-8, pp. 28-29)

Given the magnitude of the requested increase in the General Rate Case, the Company made two modifications to the rate design in the filing of the Schedule 7 tariff in its direct case in the General Rate Case. (Ex. T-567, pp. 7-8) First, the start of the second block was raised to 800 kWh inasmuch as the 500/400 blocking had the effect of increasing bills nonproportionately to many of the residential customers. (Ex. T-567, p. 8) The adjustment of moving half of the current second block to the first block was made in the interest of rate moderation. Second, the Company moved away from the strict formulation used to develop the tail block rate in the original filing. Two problems with application of the formulation were revealed. First, the tailblock could not be precisely calculated at the time of the filing inasmuch as the Company had no knowledge of future the Schedule 100 (PRAM) or 94 (residential exchange) rates. Additionally, Schedules 94 and 100 can change annually. Second, strict application could result in flattening the inclining block rate too much and reducing the "apparent" price signal. From an economic perspective it is inefficient to charge above marginal cost, but this inefficiency must also be weighed against both the signal the typical customer perceives and equity impacts.

(schedule 100) from the water heat marginal cost and adding the exchange credit (schedule 94). (See Exhibit T-8, p. 34)

The rebuttal presentation in the General Rate Case preserves the structure with the second block commencing at 800 kWh. (Ex. T-___ (DWH-7)) This approach gives the marginal cost price signal to the largest percent of customers possible while simultaneously addressing equity and implementation concerns. The basic charge of $5.00 for a single phase customer uses the basic customer approach detailed in Exhibit 566, p. 2 (which is translated to the basic charge in Ex. T-569, p. 3).

Staff's proposal to set the second block to commence at 600 kWh[16] should be rejected. The customer impacts resulting from this proposal are not equitable. Lights and appliance customers would receive half of the average rate increase, while space heat customers would get twice the average increase.

The Company requests that the Commission recognize the balancing of equity and efficiency and adopt the rate design set forth in the General Rate Case rebuttal presentation.

2. Experimental Water Heater Rate

Summary of Argument:

- The Commission should affirm the Company's analysis that the residential interruptible water heater credit is not cost effective at this time. The Company, at the request of the Collaborative Group and Task Force, extensively studied the economics of this proposal. The Company's conclusion, which Staff has confirmed, is that it is not cost effective.

- Public Counsel, arguing for a higher rate, cites a report by WSEO that recognizes a range of costs and simply assumes that the lowest cost was available

[16]See Staff response to Bench Request No. 6 (Ex. 81).

without considering other information in the WSEO report regarding the range of costs, examination of system characteristics, or review of water heat load factors on the Company's system.

Based upon the recommendations of the Collaborative Group and the Task Force, the Company did an extensive evaluation of an interruptible water heat rate. The Company originally offered an interruptible water heat rate, which featured a monthly discount of $5.35. (Ex. T-8, p. 35; Ex. 15) Upon further analysis, the Company determined that the original estimate on the value of interruption was significantly overstated, and that the monthly discount would be less than $1.00 per month. As stated in Mr. Hoff's direct testimony in the General Rate Case, the Company concluded that this credit would be too small to interest anyone, so this tariff was withdrawn. (Ex. T-567, p. 7) Staff concurs in the Company's conclusion that this proposal should not be included. Exhibit T-33, page 18.

Public Counsel, for its part, argues that the credit should be higher inasmuch as the Company assertedly has overstated the installation costs of the interruption devices. The studies cited by Public Counsel, however, do not support its position. The BPA testimony cited by Public Counsel witness Lazar (Ex. 52) shows the cost of water heater control management program as $313.57 per installation, which supports the Company estimate of $300. (Tr. at 1618) Moreover, the WSEO study cited by Mr. Lazar (Ex. 51) includes installation costs ranging from $135 to $935 per unit.

3. Hookup Charges

Summary of Argument:

- The use of hookup charges as proposed by Public Counsel is a punitive measure aimed at space heat customers who may not have a viable alternative. Any consideration of a hookup charge should await a study of the costs of adding new customers to the system.

The Company considered hookup charges for site-built and manufactured housing at the request of some members of the Collaborative Group. In conjunction with the Conservation Technical Collaborative Group, the Company determined that the current residential energy code already incorporates the full range of conservation measures that are cost-effective from the Company's perspective. In addition, the Company, together with others throughout the region, participated in the regional manufactured housing assistance program to deal with energy efficiency in residential housing not under Washington State Energy Code jurisdiction.

Public Counsel claims that current codes are not sufficient and has proposed hook-up fees that would apply to new residential space and water heat. This approach, which would not apply to new load generally, is too restrictive. Moreover, hook-up fees appear to be a punitive measure designed to drive residential space and water heat customers to alternative fuel sources which may or may not be more cost effective from the customer's perspective. Finally, such charges do not appear to be cost-based. (Ex. T-83, p. 21) These charges were discussed with the Collaborative Group, and they concluded that such charges were not appropriate.

4. Low-Income Rates

Low-income rates were discussed in depth by both the Collaborative Group and the Task Force. The Task Force recommended against these rates, and the Collaborative Group did not endorse them as a concept. The Company is not proposing any further action at this time beyond the current program of targeted conservation and assistance through the Energy Fund.

B. Secondary General Service Rate Design

Summary of Argument:

- The Company's proposal to reconfigure secondary general service rates reflects the large diversity of energy users in the current class. The proposed segmentation is important to the goal of requiring each class to pay its appropriate costs.
- Public Counsel continues to incorrectly characterize Schedule 25 as having declining block rate.

The current secondary general service rate class includes a diverse group of customers ranging from the small "mom & pop" store to the high rise office building and manufacturing facility. Over 20% of these customers have average monthly consumption of less than 500 kWh/month, and approximately 93% of these customers have demands of less than 50 kW. (Ex. T-8, p. 39)

The Company is proposing to separate the nonresidential secondary general service rate, the current Schedule 24, into three schedules:

- customers with an estimated monthly billing demand of less than 50 kW (these customers generally would not have a demand meter);

- demand metered customers with an estimated monthly billing demand between 50 kW and 350 kW; and

- customers with an estimated monthly billing demand of greater than 350 kW.

Each of these schedules is proposed to have seasonalized energy rates. In addition, Schedules 25 and 26 would have seasonalized demand charges. Rates for these three schedules, as originally proposed, are provided in Exhibit 12.

a. Proposed New Schedule 24

Each customer would pay a basic customer charge of $5.00 (single phase) each month. This customer charge was developed using the customer-related costs allocated to this class in Ms. Lynch's testimony. Seasonalized energy charges under Schedule 24 are proposed to be $0.058313/kWh during summer months and $0.064144/kWh during winter months, based on the rebuttal revenue requirement in the General Rate Case. These charges were calculated simply by dividing the class revenue requirement (less basic charge revenues) by kWhs and applying the seasonal differential.

b. Proposed Schedule 25 Rate

This schedule is similar to the existing Schedule 24 Rate, except that Schedule 25 has two energy blocks. The customer charge for Schedule 25 is increased to reflect the customer costs allocated to this sector under the cost of service model. The demand charges apply to all adjusted billed demands over 50 kW.

The demand charge is seasonalized, with a 50% differential between the summer demand rate and the winter demand rate.

The first block energy rate, which incorporates demand charges, was adjusted to reflect the overall change in revenue requirements assigned to this schedule. The remainder of the target revenue requirement was divided by the kWhs consumed in the tail block, then adjusted to achieve a 10% differential between winter and summer.

Public Counsel objects to this rate design, claiming that it is declining block. It is declining block, however, only for customers with low load factors inasmuch as the demand charge is incorporated in the first energy block. The Company recognizes the "appearance" of the declining block, and worked with Staff to develop an alternative design. (Tr. at 1510) However, no workable alternative with acceptable rate impacts was identified.

c. Proposed Schedule 26 Rate

This proposed schedule has a single energy and demand block, and is similar in structure to Schedule 31. The seasonal energy rates of $0.043819/kWh in winter and $0.039835/kWh in summer were set by dividing the energy-related revenue requirement allocated to this class under the cost of service study by the number of kWhs this class used during the test year, and applying a 10% differential. The demand charge is similarly derived by dividing the demand-related revenue requirement allocated to the class in the cost of service study by the total demand metered during the test year (after with an adjustment for the impacts of the power factor adjustment).

d. Schedule 29 Rate

Schedule 29, Seasonal Irrigation and Drainage Pumping Service, has historically had rates that are less than under the secondary general service schedule, Schedule 24, due to the acknowledgment in the region that irrigation customers have separate cost characteristics than non-irrigation customers. (Ex. 18, p. 24) Although the existing rate for Schedule 29 is below Schedule 24, it is roughly equivalent to the excess over parity which our cost of service study suggests is currently being paid by the secondary general service class. Schedule 29 rates therefore need little adjustment to reach the 1.00 target parity ratio identified earlier.[17] The Company proposes to adjust Schedule 29 to make the winter rates and basic charge similar to those under the other general service schedules, and to adjust summer rates in a manner that produces an overall increase for this customer class, which exceeds the increase applied to the total secondary class by approximately 6%.

C. Primary/High-Voltage Rate Design

Within the primary/high voltage rate category, four items remain at issue: adoption of the Company's optional marginal cost rate proposals for large load customers; interruptible rate

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[17]Schedule 35, Seasonal Primary Irrigation, is proposed to get the same increase as the primary class.

proposals; the imposition of notification requirements for large customers; and the creation of a new, separate rate schedule for SWAP customers.

1. Marginal Cost Rate Proposals

Summary of Argument:

- The Company's large power marginal cost rate proposal reflects an innovative pricing approach.

- Both Staff and Public Counsel's modifications should be rejected. Staff's modification is inappropriate since billing data are not available for new customers, nor has it identified how its proposal could be made workable. Public Counsel's modifications should be rejected since it would give some customers significant bill increases and others significant decreases due to large changes in annual consumption. In addition, the Company currently does not have the billing system to implement the rate on a wide-scale basis.

The Company propose to provide a marginal cost price signal to primary and high-voltage customers through an experimental approach whereby customized energy and demand blocks are assigned to each customer. This is the best way--and the only approach offered--to deal with the large variations in consumption and demand within these customer classes. The Company's proposed rates are described in Mr. Hoff's testimony (Ex. T-8) at pages 46-48.

A benefit of creating a marginal cost rate is that it promotes economic efficiency at the facility and thereby promotes the goals of integrated resource planning and encourages conservation. The customer is given the correct price signal to conserve inasmuch as the savings associated with energy in the tail block is priced at marginal cost. If the customer decides to increase consumption, the customer will pay the full cost of the expansion. The proposed rate design is also equitable because (1) the customer would see no change in its bill with no change in consumption, (2) the rate in its current form is proposed as experimental and voluntary, and (3) the rate is symmetric inasmuch as the customer's bill both increases and decreases at marginal costs.

Staff proposes to revise the Company's proposal to make it mandatory for all new large customers. Inasmuch as the billing data necessary to set rates are not available for new customers, Staff's proposal does not appear to be workable. (Tr. at 1514) Public Counsel, for its part, proposes that the rates be mandatory for all customers, or not offered at all. In the Company's view, making this offering mandatory would lead to unacceptable customer impacts. Many customers would experience significant bill increases or decreases due to large changes in annual consumption. Public Counsel ignores the risks associated with implementing a rate design that is untested anywhere in the nation. Rather, implementation should await the evaluation of the Company of its limited experiment. In addition, the Company currently does not have the billing system to accommodate implementation of its rate for all large customers.

2. Interruptible Rates for Large Users

Summary of Argument:

- The Company's interruptible rate proposals reflect the goals of the rate design case: to align rates with integrated resource planning. The credits offered reflect the market price of capacity.

- Although WICFUR believes that the rates are too low, the only consequence will be not enough subscribers. Furthermore, all customers will be better off if the Company can secure the interruptible load "resource" below the market price of capacity.

- Schedules 43 and 46 should be closed. The modified wording on Schedule 43 worked out by the Company and Staff should be incorporated into the tariff to correctly specify the conditions under which customers can remain on Schedule 43.

The Company's proposals reflect the interest by all parties to modify and expand the interruptible rate option to attract and qualify more customers for the rate. Two types of interruptible rates for large users were discussed by the Collaborative Group: a rate where the customer commits to an interruption as defined in a contract, and a voluntary rate where the customer can curtail and receive a credit but faces no penalty for not curtailing load.

The Company currently has two interruptible rate schedules: Schedule 46 applies to high-voltage customers, and Schedule 43 applies to all electric schools served at primary voltage. Schedule 46 customers can be interrupted during the morning or evening peak periods, while Schedule 43 customers can be interrupted during the evening peak period. Customers under Schedule 43 must reduce their load to 0.6 watts/square foot or face demand charge penalties. The Company proposes that the current Schedules 43 and 46 be closed to new customers, and that new interruptible rates be offered as follows:

- all customers with a winter load factor of at least 60% who are willing to commit to reducing their load by a specified contract amount during an interruption period will qualify for an interruptible rate,

- interruption contracts will be available for one and five years,
- the reduction in demand charges will be a function of the amount of load interrupted and the length of the interruption contract, and
- there will be penalties for failing to interrupt.

The new rates are meant to be more general and more flexible than the existing rates, and therefore should be preferred by our current interruptible customers. However, in specific instances they might not be. Customers on existing Schedules 43 and 46 will therefore be allowed to decide which rate they prefer, and for those customers who remain on existing schedules, the current relationships between the demand charges for Schedule 31 versus Schedule 43 and Schedule 46 versus Schedule 49 will be maintained in all future rate changes. Schedules 43 and 46 will not be available to new customers upon approval of the proposals offered here.

Based upon the concerns of Staff,[18] the Company is proposing to amend the availability terms of Schedule 43. The first modification allows the tariff to be phased out to new customers over a one-year period. This will allow new schools on the schedule if their energy plans have already been approved by the Washington Energy Office and they start construction by October 1, 1994. The second change requires schools to install recommended cost-effective conservation by October 1, 1995 to

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[18]Tr. at 1512.

remain on the schedule. The specific changes in the availability terms are shown in Exhibit 88.

a. Interruptible Service Credit--Firm

The objective of the interruptible service credit for firm power is to extend an interruption option to more customers so the potential for interruption resources in our Integrated Resource Plan can be increased. Interruptions provide an alternative to peak generating resources. The value of firm commitments by customers to interrupt load during peak load periods is the potential delay or avoidance of acquiring peak load resources for the needle peak hours. All customers are better off if the customer credit for interruption is less than the cost of acquiring a peak resource (after adjustment to reflect customer notification and other administrative costs).

The Company is proposing three riders--36, 38, and 39--that would apply to Schedules 26, 31, and 49, respectively. These riders, initially presented in Exhibit 12, contain three classifications (long-term firm, short-term firm, or non-firm[19]) based on the particular customer's commitment to the interruptible rate program. Each of the firm classifications has two components. The first component is a monthly credit applied to billable demand that is in excess of the customer's contracted firm kW demands. Second, a credit is paid for each interruption based upon the value of the imputed kWh above the firm demand

[19]The non-firm option was removed from Rider 36 because it was not cost-effective.

level not consumed, less verification costs. The calculation of the credits is described in Mr. Hoff's testimony (Ex. T-8) at pages 51-54.

b. Interruptible Service Credit--Non-Firm

Under the non-firm rate, the customer decides whether to interrupt service in response to the Company's request. Since the customer under the voluntary rate does not agree to interrupt at our bidding, it is not a "firm" resource. Accordingly, customers would be compensated only if and when they actually interrupt their service at the Company's request. The rate was calculated by reducing the value of the firm interruptible rate by a "non-firm" factor, based on a reasonable expectation of the number of customers that will actually interrupt when asked. The derivation of the rate is explained in Mr. Hoff's testimony (Ex. T-8) at pages 51-56.

3. Notification Requirements for Large Load Customers

Summary of Argument:

- Notification requirements should not be imposed for large customers.

Public Counsel recommended that large load customers be required to notify the Company in advance of material changes in load. The Company opposes this proposal. First, Section 11 of the Company's General Rules and Provisions (Schedule 80) already imposes a requirement on customers to notify the Company of large load increases that may damage Company equipment. Second, such a requirement assumes the customers themselves know of these changes with a long lead time, and are willing to make these decisions public. This is not the way businesses typically operate. Third, this requirement further assumes that large customers do not already keep the Company informed to the best of their ability. The reality is that these customers currently work very closely with the Company on expansion plans. Fourth, the economic benefits of a notification policy have not been demonstrated. Fifth, such a requirement would seem to be at odds with the Company's public service obligations. Finally, the examples in Exhibit 53 upon which Mr. Lazar relies in proposing his notification requirement are inapposite. Six of the contracts involved agreements between BPA and direct service industries, a special category of customers under the Northwest Regional Power Act; and another six of the cited agreements are wholesale arrangements between utilities, not retail arrangements between a utility and its customers. (Tr. at 1685)

4. Separate Rate Schedule for SWAP

Summary of Argument:

- SWAP's proposal for a separate rate class "for customers like SWAP" should be rejected. SWAP does not represent a homogeneous customer group.

- SWAP's amended proposal for a separate class for summer peaking customers should also be rejected for two reasons. First, the Company has proposed the correct seasonality in charges. Second, that logic would require a dramatic change in rate structures since 42% of primary voltage customers are summer peaking.

The Company should not be directed to establish a separate rate class for SWAP customers. The Commission should be very cautious about establishing additional customer classes. It may be appropriate to create a new customer class if a homogeneous group can be identified with a clearly defined usage pattern that sets the cost to serve that group apart from others in the schedule, or if there are compelling arguments that all customers would be better off. In the case of SWAP, these conditions have not been demonstrated.

The group which should receive a special rate, according to SWAP, is composed of "customers involved in frozen food storage and food processing that have loads that tend to peak in the summer and fall rather than the winter like other Puget customers." (Ex. 67) This group is not homogeneous. Frozen food storage and food processing are not considered homogeneous enough by the Federal Government to be assigned the same Standard Industrial Classification, even at the summary two digit level. Nor does the group have a unique usage pattern; 33% are winter peaking. (Ex. 69) The fact that some of these customers peak in the summer and fall is not unique. The Company's analysis shows that fully 38% of Schedule 31 customers and 65% of Schedule 49 customers peak during the summer and fall period included in SWAP's definition. (Ex. 85)

Another problem with SWAP's customer definition is that SWAP's definition of the summer-fall season (June through November, according to Ex. 67) is arbitrary and does not correspond to the Company's power supply situation. For instance, the Company buys peaking capacity during November.

It should be noted that SWAP customers will benefit from the Company's rate design proposal even though a separate schedule is not created for them. Due to the increased seasonality of the rates in our proposal, the average rate increase for SWAP customers will be 3% lower than the average rate increase for others in their schedules, according to Ex. T-83, p. 9.

D. Other Rate Design Proposals

1. Proposed Power Factor Adjustment

Summary of Argument:

- The Company's proposed modification in billing for power factor correction is more representative of the cost to all customers of the cost burden that customers with low power factors create than the current rate. These costs include supplying additional generation capacity (the additional demand is not registered on the demand meter), generating more electricity to compensate for additional energy losses, and additional electrical equipment required to serve the unmetered capacity.

- SWAP's objections to the charges for low power factor customers fails to consider that the customer causing the low power factor can typically correct the problem at a lower cost than the Company.

This issue was raised by members of the Collaborative Group and the Task Force, who expressed some concern that the current charges imposed on customers with poor power factors are too low. The Company currently has a reactive power charge denominated by a Killovar hour, or kVarH, that is charged to all secondary and primary voltage customers with over 100 kWs of demand. High-voltage customers pay a reactive power charge in their kVa charge.

Reactive power requirements create a requirement on the system that is not measured with standard kWh/kW meters. This additional requirement, if uncorrected, may require the need to increase the capacity of distribution and substation transformers, distribution and transmission conductors, and increase generation requirements. Another impact is that supplying customer reactive power requirements can increase system losses associated with the larger kVa requirements.

(Ex. T-8, pp. 58-59)

This proposal applies to Schedules 25, 26, 29, 30, 31, 35, and 43. It does not apply to the high-voltage Schedules 46, 48, and 49 because the demand meters used meter kVa directly, the preferred method of measuring power factors. The proposal effectively results in charging secondary and primary voltage customers in the same way as high-voltage customers, without the requirement of installing expensive new metering equipment. The customer's power factor is used to adjust the metered demand. The calculation, shown in the tariff sheet in Exhibit 12, essentially produces the effect of a kVa charge for customers with power factors below .95. This is considered to be reflective of the actual cost to the Company of serving the extra load and supplying the extra energy losses associated with reactive power requirements.[20]

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[20]It should be noted that other utilities charge for power factors this way. Snohomish PUD, Tacoma City Light, and Idaho Power adjust metered demand by the customer's power factor. The utilities have different base levels ranging from 0.85-0.95 power factors and slightly different ways for adjusting

Under the proposed power factor adjustment, customers with a power factor of 95% or above would see a decrease in their rates. Customers with poor power factors would see an increase, while the average customer would see very little change. The average change for Schedule 31 customers is an increase of about 3%, while secondary customers (Schedules 25 and 26) would see an increase of about 2%. (Ex. T-8, p. 60)

SWAP witness Carter has recommended rejection of the Company's proposal, primarily on the grounds that it would be cheaper for the Company to install capacitors to improve power factor. (Ex. T-58, page 16) His "analysis" of the costs that the Company would incur fails to consider that in many cases line capacitors cannot be installed near the customer premise. See Exhibit 65. Moreover, there is no basis for the assumption shown on his Exhibit 66 that the Company would achieve economies of scale in "fixing" the power factor problem.

2. Seasonality in Demand Charges

Summary of Argument:

- The Company's introduction of seasonality to demand charges and increased seasonality in energy charges is a significant change.
- A further increase in seasonality as suggested by SWAP is not justifiable.

The Company's proposal adds further seasonality into demand charges. The high-voltage schedules already include seasonality

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for the power factor. For example, Tacoma City Light multiplies the metered demand by 0.95 and divides by the average power factor.

through the 100% demand ratchet for peak demands which occur during the winter. Schedule 31, for its part, uses a 60% ratchet. In addition to the current demand ratchets, seasonal demand charges would be added to Schedules 25, 26, 29, 30, 31, 35 and 43. (Ex. T-8, pp. 60-61)

Seasonality in the demand charges of these schedules would be reflected by using a monthly demand rate which varies by season. Seasonal differential rates are introduced by applying a 50% differential to demand charges. The advantage of this type of seasonal differential is that it is easy to understand and it gives a price signal throughout the year.

SWAP proposes a further increase in seasonality. (Ex. T-58, p. 12) This further increase cannot be justified, however. First, seasonality in costs are difficult to identify in a hydro based generation system. Second, increased seasonality will destabilize receipts. Third, although on a forward looking basis the marginal costs are reflecting an increase in seasonality, the embedded costs reflect significant fixed costs that do not vary by season. Thus, further movement would be inequitable.

3. Allocation of PRAM Revenues

With respect to allocation of PRAM revenues across classes of customers, the Company proposes that the demand portion of the rate be eliminated and that the charges per kWh be the same for all blocks in each schedule. (Changes per kWh would continue to be different across schedules.) The existing tariff increases each block by an equal percentage; the proposed change would increase each block within each schedule by an equal cents per kWh. (Ex. T-567, p. 8) The purpose of the change in the design of the Schedule 100 rates is to make tracking of the PRAM easier.

Two further modifications to PRAM rate design are recommended. First, irrigation customers would receive an appropriate share of any rate change. Second, an explicit adjustment will be made for wholesale customers as described in Mr. Lauckhart's testimony (Ex. T-1, pp. 14-15) and the PRAM 3 proceeding (Docket No. UE-930622). Apart from these exceptions, this proposal does not depart from the existing practice for spreading PRAM revenues to customer classes.

VII. CONCLUSION

For the foregoing reasons, the Company recommends that the Commission approve (1) the cost of service methods used by the Company and the target parity ratios produced thereby and (2) the rate design proposals offered by the Company.

Respectfully submitted this 9th day of July, 1993.

PUGET SOUND POWER & LIGHT COMPANY

By ______________________
James M. Van Nostrand
Perkins Coie
Attorneys for Puget Sound Power & Light Company

ATTACHMENT A

Summary of Company's Cost of Service Study

A. Cost of Service Studies Generally

The cost of service process typically includes three steps: (1) functionalization of costs, (2) classification of costs, and (3) allocation of costs among customer classes.

1. Functionalization of Costs

Functionalization identifies the task that the utility is performing when it incurs the cost. The list of tasks or functions typically identified in a cost of service study are **production or generation** of electricity, **transmission** of that electricity to the local area, **distribution** of that electricity to the customers or points of delivery in the local area, provision of **customer service, billing, and facilities** to each customer in the service area, and a **general** function which includes costs such as administrative and general expenses. Some studies, including the one proposed by the Company, further identify tasks or sub-functions such as **coal-fired production** of electricity, **hydro-electric production**, **generation-related transmission** of electricity and **non-generation-related transmission** of electricity.

2. Classification of Costs

This step of the cost of service process involves the separation of the functionalized costs into classifications based on the components of utility service being provided. The three principal cost classifications for an electric utility are demand-related costs (costs that vary with the kW demand imposed by the customer), energy costs (costs which vary with the energy or kWh that the utility provides), and customer-related costs (costs that are related to the number of customers served). (<u>**See**</u> the NARUC Manual, p. 23).

The classification issues most often contested are: (1) whether the predominance method should be used (i.e., if a function is predominantly energy (or demand) related, it would be classified as 100% energy (or demand)); and (2) if the predominance method is not used, the determination of the proper classification scheme for each function (i.e., what relative portions should be classified to energy, to demand, and to customer).

3. Allocation of Costs

The NARUC Manual at page 25 provides a good description of this process:

> After the costs have been functionalized and classified, the next step is to allocate them among the customer classes. To accomplish this, the customers served by the utility are separated into several groups based on the nature of the service provided and load characteristics. . . . It may be reasonable to subdivide the . . . classes based on characteristics such as size of load, the voltage level at which the customer is served and other service characteristics such as whether a residential customer is all electric or not.

The functionalized and classified costs are allocated among the classes as follows:

- Demand-related costs--Allocated among the customer classes on the basis of demands (kW) imposed on the system during specific peak hours or specific peak situations.

- Energy-related costs--Allocated among the customer classes on the basis of energy (kWh) which the system must supply to serve the customers.

- Customer-related costs--Allocated among the customer classes on the basis of the weighted number of customers. Normally, weighting the number of customers in the various classes is based on an analysis of the relative level of customer-related costs (service lines, meters, meter reading, billing, etc.) per customer.

See NARUC Manual, pp. 25-26.

The goal of a cost of service study is to allocate the costs according to the nature of the constituent costs. Accordingly, the best method is the one that best reflects the planning, engineering and operating characteristics of the electric utility system. The appropriateness of either the classification method or allocation method may change over time as the utility's operating environment, customer mix or regulatory or technological environment change. So, even though the basic customer method, for example, may be appropriate today for classifying distribution costs, it may not be appropriate in the future.

B. The Company's Cost of Service Study

The Company's cost of service study is presented as Exhibit 79. This costing analysis apportions the revenue requirement to the customer classes on the basis of cost occurrence. In preparing the analysis, costs which could be identified with a particular class of customers were directly assigned to that class. Those costs which were not directly assigned were first functionalized into five major functions: (1) production, (2) transmission, (3) distribution, (4) customer service, billing and facilities or (5) general. The costs within each major function were then classified by service characteristics and apportioned to the customer classes on the basis of the contribution of each class to the occurrence of those costs.

1. Functionalization of Costs Under the Company's Cost of Service Study

Costs were generally functionalized on the basis of FERC accounting. Rate base items and expenses were functionalized among production; transmission; distribution; customer service, billing and facilities; and general.

2. Classification of Costs Under the Company's Cost of Service Study

Costs were then classified according to whether they are demand-related, energy-related or customer-related. Page 1 of Exhibit 564 (CEL-2) is a chart which shows the classification methods for each major functional area. This chart relates the 5 major functions to the standard classifications used.

a. Classification of Production Costs

The Company is proposing to use the peak credit method to classify production costs between demand and energy. The peak credit method considers the economic alternatives or opportunity costs of meeting system energy and peak requirements with existing production resources. This method recognizes that although a baseload plant is typically dispatched to provide long-term energy, it also contributes to total system peaking capability.

The Company proposes to use the peak credit method because this method was endorsed by the Collaborative Group (**See** Concept No. 6, Exhibit 11 (DWH-4), p. 19); it has been used by the Company for at least the past ten years; and it is an approach considered reasonable by the Company's system planners; and it allows forward-looking capacity and energy relationships to be reflected in the classification of embedded plant.

All production plant and related expenses and power supply expenses were classified between demand and energy using the peak credit method. This results in 16% of these costs being classified to demand and the remainder to energy. Pages 2-3 of Exhibit 564 (CEL-2) show the calculation of the peak credit factor.

The effect of using the peak credit method as opposed to alternative classification methods for production plant is shown in Exhibit 6 (CEL-5), discussed later in my testimony. Typically, methods that assign more costs to demand result in a higher overall allocation of revenue requirement to the lower load factor customer classes (residential, for example) and a lower overall allocation to the higher load factor customer classes (high voltage, for example). As shown on page 2 of Exhibit 6 (CEL-5), the scenario that classifies production costs as 100% demand-related results in a parity ratio of 81% for residential as compared to a 146% parity ratio for the high voltage class. Similarly, the energy only allocation method results in parity ratios of 97% and 77% for residential and high voltage, respectively.

b. Classification of Transmission Costs

Transmission plant and expenses have been further functionalized into non-generation-related and generation-related transmission components or sub-functions. Non-generation-related transmission costs refer to costs associated with the Company's transmission system network. Generation-related transmission costs refer to costs for those transmission lines constructed in order to connect remote generation facilities to the system network.

The Company has classified the non-generation-related transmission as 100% demand-related, recognizing that the primary design consideration used in the planning and construction of the network (non-generation-related transmission) is the peak load the facilities must carry (given a set of reliability standards). The Company's proposal classifies generation-related transmission using the peak credit method, recognizing the association to the generating facility.

The Company classified the non-generation-related plant in this manner because, according to the Company's transmission system engineers, the principle reason the Company is investing in transmission plant is in response to peak loads. In other words, the system's peak demands are the primary consideration when analyzing the need for new transmission plant.

c. Classification of Distribution Costs

The Company proposes to classify distribution costs as either demand-related or customer-related based on the basic customer method. Under the basic customer method, only those distribution costs relating to metering and service drop are treated as customer-related. All other costs are classified to demand. In effect, this method implies that the only costs which vary directly with the number of customers on the system are the cost of the meter and service drop (and related expenses).

We are using the basic customer method for purposes of this filing primarily in the interests of promoting consensus, although the Company continues to believe in the merits of the former approach.

d. Classification of Conservation Costs

The Company proposes to treat conservation investments and related expenses in the same manner as production costs. That is, these costs are classified between demand and energy using the peak credit method. This treatment recognizes that conservation is a resource and should be treated as such for rate design purposes.

e. Classification of General Costs

These costs include investment in general plant, administrative and general expenses, local, state and federal taxes, etc.

These costs are generally classified and allocated following the classification and allocation of the four main functions. It should be noted that the Collaborative Group made several endorsements in the area of general costs relating to the treatment of administrative and general expenses, general plant and federal income taxes.

(**See** Concept Nos. 8, 9 and 10 of the Collaborative Group, Exhibit 11 (DWH-4), p. 19.) The Company has applied the endorsed concepts in its proposed cost of service study.

3. Allocation of Costs Among Classes Under the Company's Cost of Service Study

Historically, the Company considers six broad classes of customers: residential, secondary voltage, primary voltage, high voltage, street and area lighting, and firm resale. These classes are identified in large part according to the delivery voltage at which they take service.

Delivery voltage refers to the point on the distribution or transmission system where the customer is taking service. For our residential and secondary general service, this is less than 600 volts. Delivery voltage for primary service is greater than 600 volts but less than 50,000 volts, and the high voltage class takes service directly from the transmission system, above 50,000 volts.

Within each of the six broad classes of service, the Company has identified subclasses of service. Page 7 of Exhibit 3 (CEL-2) presents the six broad classes of service, the associated subclasses, and some descriptive attributes and assumptions about each group. It is these characteristics that drive the allocation of costs to the specific group. The cost of service study is based on assumptions and characteristics regarding the service requirements of each class or subclass of customer included in the study. Typically, these characteristics involve delivery voltage, degree of diversity, degree of coincidence, and magnitude of usage. These characteristics can be defined in terms of demand-related, energy-related and customer-related components.

Once costs were classified into demand-related, energy-related and customer-related components, costs were then allocated to the customer classes on the basis of the contribution of each class to the total kilowatts of demand upon various segments of the system, total consumption of kilowatt-hours, and total number of customers in each class. The demand, energy, and customer allocation factors were adjusted and weighted to further reflect the actual occurrences of costs within the allocation process.

a. Allocation of Demand-Related Costs

As described above, demand-related costs can be identified in the production, transmission and distribution functional areas. Two separate sets of demand allocation factors are typically developed to allocate this classification of costs: system coincident peak demand factors and class non-coincident peak demand factors. These two sets of demand-related allocation factors are shown in Exhibit 564 (CEL-2), page 4.

Even though demand is recognized as a key consideration in the planning and investing in facilities in all the functional areas of a utility's system, the term demand is almost too broad. Actually a cost study will identify costs incurred as a result of a localized or non-coincident demand on a substation as opposed to costs incurred as a result of the combined demands on the system at time of system peak (allocation of production or transmission costs, for example). The timing of the demand or high usage is the key factor. The two sets of demand allocation factors are an attempt to reflect this sensitivity to different times of high use on the system in terms of cost causation.

Within each set of demand allocation factors, it may be appropriate to exclude the peak contribution of a given class depending upon the functional category being allocated. The nature of the cost to be allocated must be considered in light of the service requirements of the customer. An example of this is the exclusion of the high voltage class' NCP demand when calculating the allocation factors used to allocate distribution demand-related costs, given that high voltage customers take delivery off the transmission system.

System coincident peak demand refers to the load required by a given class of customer when the system peak load occurs. System coincident peak demands are generally used to allocate production and transmission demand-related costs, since these functional cost areas are designed or incurred in order to either produce or deliver the peak demands placed on the system.

The Company identifies the actual hours in the test period of highest system coincident peak demand. Using load research information, the Company then identifies the contribution of each class to these hourly peak demands and makes adjustments for peak losses. Either the single highest or extreme system coincident peak demand or the average of some or all of the high system coincident peak demands are then used to compute the set of system coincident allocation factors. The number of hours utilized in the calculations, in turn, are dependent on the functional category of costs being allocated.

We are proposing to use 200 hours, which represents the annual number of hours of operation for the combustion turbines reflected or incorporated in the Company's planning models. In our view, using 200 hours better matches the allocation factor with the planning criteria actually used by the Company. The effect of including additional hours in the calculation of the allocation factor tends to benefit the lower load factor classes, such as the residential class, at the cost of the higher load factor classes, such as the high voltage class.

Class non-coincident peak demand is the highest demand of the class at a point in time regardless of the demands of any other class. Such demands are often referred to as localized demands. These demands are derived using methods similar to those used to calculate the system coincident demand factors.

The system coincident peak demand factors are used to allocate production and transmission demand-related costs. This is in recognition of the fact that these costs are incurred in response to the peak coincident demands placed on the system. The class non-coincident peak demand factors are used to allocate distribution demand-related costs. This recognizes the fact that investments in substations, for example, are more dependent on localized class level demands than the combined or coincident peak demands.

b. Allocation of Energy-Related Costs

Energy costs are allocated using energy factors derived from the class total kWh consumption for both known and measurable change for the test period. Adjustments to normalize the results and to reflect losses are made to the class level kWh consumption figures. Page 5 of Exhibit 564 (CEL-2) shows an example of calculation of the energy allocation factor.

c. Allocation of Customer-Related Costs

Customer-related costs are generally allocated based on the number of customers or meters taking service from the utility. As in the case of the demand allocation factors, a set of customer-related classification factors are generally developed. The set is derived through a combination of weighting factors and consideration of the particular functionalized classified component of the revenue requirement being allocated. For example, the costs associated with serving only secondary delivery voltage customers should not include primary delivery voltage customers in its allocation factor.

4. Results of the Company's Cost of Service Study

Summary 1 of Exhibit 79 shows a class level income statement for each class considered in the cost study. The bottom line of this report shows the realized rate of return for each class of customers based on the allocated operating expenses, income and rate base for that class. Summary 2, line 13 shows the resulting parity ratios under this cost of service study.

5. Comparison of Scenarios

Exhibit 78 illustrates the effects of the various proposals on the class level cost of service. Schedule 1 of Exhibit 78 compares the overall results under each party's cost of service proposal. The remaining schedules in Exhibit 78 show each party's position with respect to the four contested cost of service issues.

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 Exhibit 6.

Attachment B

COMMISSION WORKSHEET

Schedule	(a) COS Parity Ratio	(b) Target Parity Ratio	(c) = (b - a) Difference Parity Ratio	(d) Average % Increase	(e) = (c + d) Estimated Schedule % Increase	(f) % or Absolute	(g) Proforma Revenue	(h) = (g * (e or f)) Estimated Rate Increase	(i) Ordered Rate Increase	(j) (i / g) Ordered Rate % Increase
7	96%	97%	1.0%				$ 510,806,403			
24	110%	107%	-3.0%				115,114,738			
25,29	117%	111%	-6.0%				127,552,381			
26	115%	110%	-5.0%				72,188,108			
31,43,35	93%	95%	2.0%				64,696,270			
46,49	88%	92%	4.0%				88,247,939			
Lighting	136%	124%	-12.0%				8,948,680			
Resale	77%	100%	23.0%				3,975,193			
Temp Adjust							28,671,567			
Total Increase							$1,020,201,279	$ 0		

Column a: Existing Cost of Service parity as viewed by the Commission.
Column b: Cost of Service targeted by Commission.
Column d: Average percentage increase projected over proforma revenue as approved by the Commission.
Column e: Simplified method of calculating increase to schedule. A more precise method is (1 + c / 100) x (1 + d / 100).
Column f: An alternative method to calculating Column e.
Column j: This rate increase level by schedule will require iteration to spread revenue requirements until Column j sums to revenue increase allowed in the order.