Exhibit ___

BEFORE THE

WASHINGTON UTILITIES AND

TRANSPORTATION COMMISSION

Cause No. UE-920499, UE-921262
Rate Design Phase

PUGET SOUND POWER AND LIGHT COMPANY

Direct Testimony of

JIM LAZAR
CONSULTING ECONOMIST

On Behalf of
Public Counsel Section
Office of the Attorney General

Cause Nos. UE-920433, UE920499, UE-921262
Cost of Service and Rate Design Phase
Direct Testimony of Jim Lazar

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, address, and occupation?

A. I am Jim Lazar, 1063 S. Capitol Way Suite 219, Olympia, WA 98501. I am a consulting economist specializing in utility rate and resource planning.

Q. Please summarize your educational background and experience.

A. Following undergraduate and graduate study in economics at Western Washington University, I served on the staff of the Washington State Senate from 1977-79. I have been engaged in utility rate consulting since 1979. My clients include utilities, regulatory bodies, state consumer advocates, industrial concerns, and public interest groups. I have appeared before state regulatory commissions in Idaho, Illinois, Montana, Oregon, California, Hawaii, and Arizona, and before numerous other local and federal regulatory bodies. I served as the lead author of a book on electric utility cost allocation and ratemaking policies published in 1982. I have appeared previously before this Commission in numerous proceedings involving Puget Sound Power and Light Company and each of the other electric and natural gas utilities regulated by the Commission. Exhibit ___(JL-1) details my qualifications.

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

A. I have been asked by the Public Counsel Section, Office of the Attorney General, to evaluate Puget's proposed cost of service methodology and rate design changes and to make recommendations to the Commission for changes which should be made to these proposals. I participated extensively in the Rate Design Collaborative on behalf of Public Counsel, and met with the Rate Design Task Force referred to by Mr. Hoff in his testimony.

II. COMPANY PROPOSALS ARE MOSTLY EXCELLENT

Q. Please give your overall impression of the Company's cost of service and rate design proposals?

A. In general, the Company's proposals are excellent, are considerable improvements over approaches used in the past, and should be viewed favorably by the Commission. I will take exception to numerous details of the Company's proposals, but my attention to the fine points of the Company's proposals should not be taken as an indication that the Company has not made progressive strides in its filing.

The Company's general approach to Cost of Service, using the Peak Credit method based on a mix of available peaking resources, assuming a 200 hour peak demand period, and allocating distribution plant using the Basic Customer / Demand method, has applied reasonable methods chosen from among many available methods. I propose some specific changes.

The Company's rate design proposals are generally progressive, although the changes proposed in the general rate case filing (UE-921262) are inferior to the options proposed in the rate design filing (UE-920499). Again, I will propose some specific changes.

Q. Briefly summarize the changes you will propose to the Cost of Service methodology presented by the Company?

A. In spite of numerous decisions by the Commission affirming that transmission plant should be allocated on the same basis as production plant, Puget has again proposed a peak demand method for transmission plant. I recommend that the Commission's consistent policy be maintained. In addition, I suggest application of the same method for allocating distribution lines for electric utilities as the Commission has ordered for use by gas utilities. Even without these adjustments, Puget's cost of service study justifies a decision that the Primary, High Voltage, and Resale classes get a much larger than average increase.

Q. Briefly summarize the changes you will propose in the area of rate design.

A. Puget has backed away from the baseline concept of rate design with its proposal in the general rate case to substantially increase the rate for the initial block of residential usage. I recommend that the initial "hydro" block of the residential rate design be retained and that high cost resources be reflected in the tailblock. This allows a more equal sharing of hydro benefits among Puget's residential customers. In the secondary general service class, I support separating the non-demand-metered customers, but oppose Puget's continued declining block rate. I generally support Puget's proposed interruptible rate options.

III. RATE AND SALES GROWTH HISTORY

Q. Please briefly describe the history of rate changes on the Puget system?

A. Most general rate cases have involved either a uniform percentage increase to all classes or a uniform cents/kwh increase to all classes. There are two important exceptions. In Cause U-82-38, the Commission apportioned the vast majority of the rate increase to the residential class, and virtually no increase to the Primary or High Voltage classes. Since that time, these classes have consistently provided revenues far below allocated costs. In Cause U-89-2688-T, the Commission used one method to apportion power supply cost increases which had been included in the ECAC mechanism among classes, and a different method to allocate other cost increases associated with the general rate case.

Q. What has the pattern of sales growth been on the system?

A. The secondary general service class has been the fastest growing class in terms of kwh sales, followed by the primary general service, high voltage, and resale classes. The residential and lighting classes have grown most slowly.

IV. COST OF SERVICE

Q. Please begin by indicating the points in the Company's cost of service study sponsored by Ms. Lynch that you support and those which you feel should be changed?

A. In general, the Company's cost of service study is a great improvement over past studies, because the long-discredited "minimum system" method has been abandoned and the Company has improved its method of determining peak-related power supply costs.

There is one area, the classification of non-generation related transmission, where I strongly disagree with the Company's approach. The Commission has consistently ruled that all transmission costs should be allocated using the peak credit method in order to recognize that a major portion of the cost of transmission facilities is associated with transmitting energy throughout the year, not just meeting peak demand.

In another area, classification of distribution plant, I think the Commission should consider using the same approach for electric plant as it has repeatedly approved for gas plant.

In addition, I strongly recommend that the Commission continue to consider factors other than the results of the cost of service study, (however it may be calculated) in setting rate levels for the various customer classes. I disagree with Puget's mechanical application of the results of the study.

A. Production Costs

Q. Ms. Lynch proposed that the Peak Credit method be used to classify generating plant costs between capacity and energy. Do you agree with the approach she has presented?

A. Yes, the method Ms. Lynch has used is appropriate for a utility system like Puget's, where the Company has the option of selecting baseload or peaking resources to meet its needs, and only a portion of the investment (or payment to a developer other than Puget) for a baseload generating plant should be considered as the cost of meeting peak demand. Other methods used in some parts of the United States which classify 100% of the investment in generating plant as demand-related are totally inappropriate for the Puget system.

Q. Are there any specific details about Ms. Lynch's calculation which you think could be done with greater accuracy?

A. Yes, there are two areas where her peak credit calculation could be more precise. In Exhibit 5, pages 1 and 2, and Exhibit 564, Pages 2 and 3, Ms. Lynch calculates that 17% and 16% of the cost of baseload generation should be treated as demand-related. There are a two corrections which I believe should be made to the studies underlying these exhibits.

In both of these exhibits, Ms. Lynch assumes that all 200 hours of operation of the simple cycle peaking unit would utilize #2 diesel fuel oil. In fact, the Company's simple cycle turbines at Fredrickson, Fredonia, and Whitehorn units 2&3 are all connected to natural gas lines, and have natural gas service. While it is probable that they would be interrupted during <u>some</u> of the 200 hours of system peak demand, it is unlikely that they would be interrupted for <u>all</u> of those 200 hours. In fact, during the test year, the gas supply to these turbines was not interrupted at all. [Deposition Request #2]

In both of these exhibits, Ms. Lynch uses Puget's overall rate of return as the discount rate in computing the 17% and 16% peak credit fraction. The correct discount rate to use is the net-of-tax cost of capital, since any deferral in payment of a revenue requirement to the utility also defers the associated income tax expense.

Q. What is the effect of changing these two factors in the peak credit calculation?

A. As shown in my Exhibit ___(JL-2), the effect of making these two changes is relatively minor, reducing the peak credit factor from 16% demand down to 13% demand. Pages 1-3 of this exhibit correct Ms. Lynch's calculation for the net-of-tax discount rate; Pages 4-6 include both the discount rate correction and also assume that only 50 hours of operation is on oil, and the remaining 150 hours is on gas.

Q. How does Puget then use the peak credit factor in its cost of service study?

A. Puget applies the 16%/84% peak/energy factor to all of the production plant costs, and to all of the power production expenses. This is an approach advocated by WICFUR in previous proceedings. This approach should be accepted in light of the changes that Puget has implemented in the calculation of the peak credit factor.

Q. How should the Commission resolve the appropriate method used to compute the peak credit factor in this proceeding?

A. The Commission should approve the basic approach used by Puget, dividing the present value of total costs of meeting incremental peak demand by the present value of the total costs of meeting incremental baseload demand, and then applying that factor to the total cost of production plant and power production expense.

The Commission should direct Puget to base the split on actual expected hours of operation on oil and on gas. Puget should use the correct discount rate in the future.

B. Puget's 200 hours definition of "peak" should be approved.

Q. Ms. Lynch has proposed using 200 hours of system peak demand to allocate those production costs which are peak demand related. Do you agree with this method?

A. It is a significant improvement over past approaches, and it is a reasonable method. Other reasonable methods would include looking at 500 hours or 1500 hours, rather than 200 hours, for reasons I will discuss below.

In the past, the Company proposed to allocate demand-related production costs based on the highest 12 hours of system demand. This approach was always controversial. As a practical matter, the Company would most economically meet such needle peaks with a combination of interruptibility and short-term off-system capacity purchases, rather than by building peaking generating plants. The use of a broader 200 hour peak more accurately reflects the planning criteria for the Company's peaking units; it is the Company's policy to keep 200 hours of fuel stored at the site, and the Company's load/resource analyses (such as Exhibit ___(JRL-8)) assume 200 hours of operation of the combustion turbines.

Q. Under what circumstances should a different definition of "peak" than 200 hours be considered?

A. In my opinion, the proper period over which to allocate the demand-related costs of peaking resources is over the hours when they are expected to be used. Given the relatively attractive price of natural gas, I think that the economics may justify operating Puget's combustion turbines for more than 200 hours per year. Puget's own planning for these units indicated an intention to operate them more than 200 hours per year.

Puget sought and obtained exemptions from the Powerplant and Industrial Fuel Use Act (PIFUA) for its combustion turbines which permitted the Company to operate them for up to 1500 hours per year for peak load purposes. It also reserved the option to seek a "reliability of service" exemption to use them for more than 1500 hours. Presumably the Company intended to use the plants for *up to* 1500 hours/year to meet peak demands, although the repeal of PIFUA means that Puget is no longer *limited* to 1500 hours.

Q. What is the effect of allocating peak demand related costs over a longer duration of "peak" load than the 200 hours Puget has proposed?

A. This is shown clearly on Ms. Lynch's Exhibit 3, Page 8. Using the Company's proposed 200 hour peak period, the residential class bears 60.3% of the demand-related costs and the primary / high-voltage class bears 15.5%. If, for example, a 1000 hour "peak" period were used, the residential share would drop to 58.6% and the primary / high voltage share would increase to 16.5%. Since some $150 million of plant investment and $75 million of power production expense is allocated on the basis of peak demand, a change of 1-2% can make a multi-million dollar impact on the bottom line of the cost of service study.

Q. How should the Commission define the "peak" period for cost of service analysis in this docket?

A. The Commission should accept the 200 hour definition used by Puget for the purposes of this proceeding, but may wish to request the parties to address in future proceedings whether a longer period better reflects the Company's investment planning. In particular, if the Commission approves the interruptible rates which Mr. Hoff proposes, it may become appropriate to lengthen the period used to define "peak" demand for purposes of allocating production and transmission plant.

C. Only half of the investment in peaking plants is demand-related.

Q. Puget's formula only considers part of the cost of a combustion turbine to be demand-related in the Peak Credit formula. Do you agree with this approach?

A. Yes. The Commission is aware that the combustion turbines can be used for far more than just meeting peak demand. Under conditions of drought, the turbines can be and are used to provide off-peak energy to supplement the hydro system. This practice is known as "hydro-firming" and is a recommended power supply strategy in the Northwest Power Planning Council's 1991 Plan. Since the plants do more than help Puget meet peak demand, only a portion of the investment cost of a peaking generating plant should be treated as a cost of meeting peak demand.

Puget has recognized this by assuming that peak demands in the highest 200 hours could be met using either purchased capacity from California or by using combustion turbines. The California intertie should not be viewed as a one-way street, and Puget has correctly recognized the economic benefits of entering into summer/winter exchanges and seasonal capacity purchases with the California utilities, which face their peak demands in the summer. Puget properly recognizes these circumstances by averaging the cost of a peaking plant with the cost of a short-term capacity contract in computing the peak credit factor. This approach should be endorsed, regardless of whether the Commission approves the 200 hour definition of "peak" or some other definition.

D. Classification of Non-Generation Related Transmission 100% to Demand is an Error.

Q. What is your most significant disagreement with Ms. Lynch's cost of service study?

A. Ms. Lynch has classified 100% of the Company's network (non-generation-related) transmission investment as demand-related, and has allocated it among the customer classes solely on the basis of peak demand. This approach is conceptually wrong, has been rejected by the Commission on many occasions in favor of the Peak Credit method, and it should be rejected again.

Non-generation related transmission is a $253 million rate base item. The method used significantly affects the outcome of the cost study. In Exhibit 6, Ms. Lynch did provide a sensitivity analysis of this item, and changing the method used from the 100% demand approach advocated by Ms. Lynch to the Peak Credit method approved by the Commission results in a 2% increase to the residential revenue:cost ratio, and a 1-5% reduction to the revenue:cost ratios for the other customer classes.

Q. Why is it incorrect to classify 100% of network transmission costs as demand-related?

A. Transmission lines are built to meet energy demands throughout the year, not just to provide service on the coldest days of the year. Even if the Company had absolutely flat demands throughout the year, with commercial air conditioniong loads exactly filling in when residential space heating loads leave off, the Company would still need a transmission system. Even if a particular customer uses no electricity at all during the time of the peak demand, the Company must still have a transmission system in place to serve it.

As Mr. Hoff and Ms. Lynch both admitted during cross-examination, there are significant economies of scale in transmission construction. Puget clearly recognizes this in its Integrated Resource Plan. Exhibit ___(JL-3) contains an excerpt from Puget's Integrated Resource Plan in which the Company explicitly states that there are economies of scale in transmission, meaning that the cost of overbuilding a transmission facility to meet a peak load is much lower than the cost of building a system sized only to meet off-peak loads.

Q. Is there an explicit situation which demonstrates the fallacy of Puget's approach?

A. Yes. As an example, Puget serves irrigation customers, who have summer peaking loads. Ms. Lynch's cost of service study, Exhibit 4, Schedule C, Page 13, Line 11, allocates zero non-generation related transmission to the primary irrigation class. There can be no question that these customers could not be served if there were no network transmission, nor is there any justification for completely exempting them from paying for transmission. That is the effect of Puget's proposal to allocate non-generation related transmission solely on the basis of peak demand, and it demonstrates why the all-demand method of allocating transmission costs should not be used.

Q. Has the Commission addressed the issue of classification of transmission plant in previous proceedings?

A. Yes, on many occasions beginning more than a decade ago, the Commission has been presented with a request by either utilities or industrial customers to classify transmission costs as demand-related, and on every occasion where the Commission has explicitly addressed this issue, it has ruled that transmission should be classified partly on the basis of peak demand, and partly on the basis of annual energy usage. I will cite a few of these decisions:

> We agree with the recommendation of POWER that transmission costs should not be fully allocated to demand but should be allocated to both energy and to demand. [U-81-41, Second Supp. Order at 23]
>
> Classification of transmission system cost should be applied using the same principles as for production plant. [U-82-10, Second Supp Order at 37]
>
> The Commission requires that the company present in the next proceeding an allocation of these [transmission] costs between energy and demand using the same principles as for production plant. [U-82-12/35, Fourth Supp. Order at 35]
>
> No party other than Counsel for POWER addressed the company's allocation of transmission costs. Counsel for POWER correctly argues that the Commission in the company's previous rate case, Cause U-81-41, ordered the company to allocate all transmission costs to demand and energy using the same principle as for production costs. The Commission also affirmed this principle in the most recent rate cases involving The Washington Water Power Company (U-82-10) and Pacific Power and Light Company (U-82-12). The Company is ordered in its next rate case to present a cost of service study that complies literally with the Commission's directive related to the allocation of transmission costs. The Commission does not intend that remote transmission costs should be allocated differently than total transmission costs. [U-82-38, P. 31]

Q. Has Puget presented any new evidence or other factors which should lead to any different result in this proceeding with respect to the classification of transmission costs?

A. No. Puget's only evidence has been presented before, claiming that the design criteria for transmission plant is peak capacity, and Puget somehow concludes from this that the costs should be allocated on the basis of peak demand.

Q. Do you disagree with Ms. Lynch's statement at page 17 of Exhibit 2, that "the primary design consideration used in the planning and construction used in the planning and construction of the network is the peak load the facilities must carry."

A. Yes and no. I agree that, once a decision is made to build a transmission line, the engineering considerations definitely include the capacity of the line, and definitely do not include the number of kilowatt-hours it will carry. However, that begs the questions of <u>why the line is built in the first place</u>, and how much of the cost is related to that peak capacity.

Transmission lines are very expensive, and utilities only build them when they have substantial amounts of power to move from place to place. Neither Puget nor any other utility would build a transmission line simply to serve peak demands on one day of the year. The decision to build transmission is based upon expected annual usage of the customers to be served by the line. I would argue that this expected usage is the "primary design consideration" used in transmission planning -- even though it may be a fact which the transmission engineers themselves never consider. If the expected usage is very small, no transmission line will be built, and there are large areas of the state which do not have transmission system access.

The decision of what size transmission line to build (i.e., the peak load carrying capacity of the line) is normally one which is made after a decision to build the line has been reached. That is the design consideration usually highlighted by transmission engineers, but at that point much of the cost has already been committed. There are very significant economies of scale in transmission construction. The cost to build a 500 kv line to carry 2000 MW of capacity is only about twice the cost of building a 230 kv line which will carry 500 MW, and the cost to build a 230 kv line is much less than twice the cost to build a 115 kv line, even though the capacity is more than twice as great, as shown in Exhibit ___(JL-3).

Q. What other considerations affect the cost of transmission lines besides peak carrying capacity?

A. In addition to the basic decision to build, which is usually based on expected need to move energy, other design considerations include capacity to permit future growth, optimal location, useful life, incremental cost of adding additional capacity in the future, access to other utility systems, maintenance costs, environmental effects of construction, and environmental effects of operation. For example, public concern about electro-magnetic fields affects how high transmission lines must be strung, a significant cost factor. This concern is one which applies throughout the year; if the only risk of EMF health concerns was on the system peak day (when few people are out wandering around transmission right of way areas anyway), the costs actually incurred mitigating this risk might be lower or zero.

Q. Is the method of allocation for transmission costs which the Commission has approved in the past a precisely accurate method?

A. No. The Commission has required that companies allocate transmission plant based on the subtotal of their production plant. This is a reasonable method, but one which is a great simplification of a truly cost-based approach. I believe that the results of a truly cost-based approach to allocating transmission costs would most likely be very similar to the method the Commission has required in the past.

Q. How would it be possible to allocate transmission costs on a cost-basis?

A. It would be a complex analysis requiring a great deal of knowledge about the transmission system and transmission costs.

First, the generation-related transmission should be allocated solely on the basis of energy. The Peak Credit method already assigns as a demand cost 100% of the costs needed to install a peaking resource within the load center. Therefore 100% of the additional costs of a remote baseload plant such as Colstrip are not incurred to meet peak demand, and are therefore energy-related. Baseload plants have higher outage rates than peaking plants, and in fact are sometimes out of service at the time of the peak. The method the Commission has approved, using the Peak Credit approach for all transmission, including that associated with remote generating plant, assigns too much of this subcategory of transmission costs on the basis of peak demand.

Second, it would be necessary to study the transmission network segment by segment, to determine which lines were overbuilt to meet peak demands, and which were built to a minimum engineering criteria needed to satisfy other standards, such as height above roads. 100% of the right of way and construction costs needed to build a basic transmission infrastructure sufficient to serve off-peak energy loads would be classified as energy-related.

Third, those costs of oversizing the system specifically to meet peak demands in excess of off-peak demands would be treated as demand-related.

Finally, one benefit of installing extra transmission capacity above that needed to serve off-peak loads is that line losses are reduced during all hours of the year. These energy cost savings should be credited against the cost of building the extra transmission capacity.

Q. What would the net result of the three-part analysis you have just described be?

A. If the Commission assigned 100% of the costs of transmission associated with remote plant, and 100% of the costs of building a local transmission network sufficient to serve off-peak needs as energy-related costs, and 100% of the extra costs needed to overbuild the transmission system to serve peak demands in excess of off-peak demands as demand-related costs, and credited the benefit of reduced energy losses against the cost of the transmission system investment, I expect that the bottom line would be very similar to the method the Commission has adopted, applying the Peak Credit method to all transmission costs. For that reason, I find that the peak credit method used for production plant and approved many times by the Commission is reasonable, and should be reaffirmed. The Company's proposed all-demand method should be rejected again.

Q. What are the results on the Cost of Service Study of allocating transmission costs in the manner the Commission has consistently approved?

A. I have estimated the impact allocating non-generation-related transmission on the same basis as production plant on Page 1 of Exhibit ___(JL-4). This shows that, at PRAM II rates, the different classes have the following parity ratios:

Revenue to Cost Ratios @ PRAM II Rates
With Transmission Costs Computed Per WUTC Directives

Residential	99%
Secondary General Service	110%
Primary General Service	90%
High Voltage	83%
Lighting	131%
Resale	70%

I made the estimates by applying the difference between the Company's 100% demand allocation method and the Commission-approved method shown in Exhibit 6, Page 4, Line 6, to the results of the Company's study at PRAM II rates using the 100% demand allocation method shown in Exhibit 565, Page 2, Line 13. Because the Residential class has received larger than average rate increases since the last general rate proceeding (upon which Exhibit 6 was based), the residential class Parity Ratio (using the Company's 100% demand transmission approach) increased from 93% in Exhibit 6, at U-89-2688 rates, to 97% at PRAM II rates in Exhibit 565, primarily because the residential class has been assigned the largest rate increases under the PRAM. When the 2% adjustment for the change in transmission allocation methods is added, the residential class Parity Ratio increases to 99%.

E. The Basic Customer Definition of Customer Costs is Reasonable, but the Demand/Energy Method Applied in Gas Cases is More Appropriate.

Q. Turning to the classification of distribution plant, how has Puget proposed these costs be calculated in this proceeding?

A. Puget has used the Basic Customer / Demand method, in which the costs of meters and services are treated as customer-related costs, and the balance of the distribution system (substations, poles, conductors, conduit, and transformers) are considered demand related. The demand-related costs are allocated based upon class non-coincident demand.

Q. How does this differ from Puget's approach in previous proceedings?

A. In previous proceedings, Puget advocated a "minimum system" method which classified about two-thirds of the distribution infrastructure as "customer-related" costs. The Commission has rejected this approach in numerous electric and gas rate proceedings, and Puget appropriately responded by discontinuing this long-discredited approach.

Q. Why is the minimum system method conceptually incorrect?

A. A utility does not build "minimum sized systems" and does not serve "zero usage customers" when it designs a distribution system. It builds the system only where it expects significant business, energy sales, and revenues. As professor Richard Bonbright noted in one of the leading historical works on utility ratemaking:

> "...for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground." [Bonbright, Principles of Public Utility Rates, 1961, p. 348]

The Commission has consistently rejected the minimum system or its variant, the "zero intercept" method of classifying distribution costs. As the Commission found in previous Puget cases:

> In this case, the only directive the Commission will give regarding future cost of service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum sized system is not. The parties should not use the minimum system approach in future studies. [Cause U-89-2688-T, Third Supplemental Order, P. 71]

Q. What other methods besides the Basic Customer method could be considered?

A. The Commission may want to consider the factors which drive the decision to install distribution plant in determining the proper method for allocating the costs of poles, conductors, and transformers. Puget's line extension policy for commericial customers is driven by expected revenues. Puget is willing to install a longer line extension for a customer expected to use more power and pay more revenue. Customers must pay the excess cost of a line extension beyond that justified by their expected revenue in the form of a contribution in aid of construction. In remote areas, this can be a very large contribution, and may affect customer decisions of where to locate their facilities.

Since expected energy use is the most important factor in the customer's expected revenue which determines the Company's investment in distribution plant, expected energy use should also be considered in allocating the costs of that plant. For example, under Puget's line extension policy, the Company will invest up to $100,000 in distribution lines for a commerical customer expected to use $50,000/year in electric service, but will invest only $1,363 in a residential line extension.

Q. How would the impact of expected energy use on the Company's investment in distribution plant be incorporated into a cost of service study?

A. A percentage of the distribution infrastructure would be classified as revenue-related, and allocated among the classes based on revenue by class at distribution voltage levels. Primary voltage plant, such as substations and overhead lines would be allocated based partly on primary voltage demand, and partly on the basis of primary voltage revenue. All customers except those in the high voltage class would share in these costs. Secondary voltage distribution plant, such as line transformers, would be allocated based on secondary voltage demand and secondary voltage revenue, and would be assigned only to customers served at secondary voltage, such as residential, small commercial, and street lighting customers.

Another approach would be to classify the distribution plant partly as energy-related, in recognition that energy-related revenue is the largest component of revenue, and in turn drives the decision to install the distribution plant.

Q. Has this commission previously directed that utility distribution plant be allocated on a combination of peak demand and annual energy use factors?

A. Yes, in numerous natural gas proceedings beginning with Cause U-86-100 the Commission has directed that distribution mains be allocated 50% on the basis of peak demand and 50% based on annual throughput. It has also directed that service connections, and meters be allocated partly on the basis of usage, compared with Puget's proposal to allocate the equivalent equipment on its electric system entirely on a per-customer basis. This was done based on testimony that the decision to install distribution plant was driven by expected throughput. The table below compares the method approved by the Commission for gas cost allocation studies with that which Puget has proposed for electric cost of service:

GAS VERSUS ELECTRIC DISTRIBUTION PLANT
ALLOCATION METHODS

PLANT	Approved Method GAS	Proposed Method PUGET
Distribution Lines	50% demand 50% commodity	100% demand
Service Connections	25% demand 25% commodity 50% customer	100% customer
Meters	25% demand 25% commodity 50% customer	100% customer

Q. What would the impact on the results of the cost of service study be if the methodology used for gas utilities were applied to Puget's electric cost of service analysis?

A. Each of the approaches used for gas utilities shown above can be directly translated to the electric utility cost of service model. In my opinion, these would form a more rational approach than either the minimum-system method, which the Commission has rejected, or the basic customer / demand method which the Commission has accepted.

Q. You have cited from the Company-prepared cost of service study applying the Commission-approved method for allocating transmission costs. Have you prepared a cost of service study incorporating the refinement to the Peak Credit calculation reflecting partial use of natural gas for peaking purposes, or the use of the method for allocating distribution plant applied in gas proceedings?

A. No. The parties agreed to attempt to use the Company's cost of service model to facilitate a common format. In spite of the Company's efforts to provide training, I have been unable to complete the revised cost of service study. If it can be completed in the near future, it may be filed as a late-filed exhibit. The impact of these appropriate changes is fairly predictable, and is indicated in the probably cost of service results shown on Page 1 of Exhibit ___(JL-4):

1) Reducing the peak credit demand allocation fraction to 13% will reduce costs for the lower load factor residential class.

2) Classifying transmission using the peak credit method will reduce costs for the lower load factor residential class.

3) Classifying distribution plant partly on a revenue or energy basis will reduce costs for the smaller-use classes (residential and the smaller secondary subclasses).

As shown in Exhibit 6, the transmission cost allocation change alone increases the residential parity ratio by about 2%, and reduces those for other classes. I expect that the other changes would make a similar amount of difference on the parity ratios, raising the residential parity ratio above 1.00, and reducing those for the primary and high voltage classes even further below the already inadequate levels.

My basic recommendation is that the Commission should determine what elements it wants included in the study, and direct the Company to include a study consistent with those determinations in its rebuttal testimony in the general rate proceeding.

V. FACTORS OTHER THAN COST OF SERVICE WHICH SHOULD BE CONSIDERED IN SPREADING COSTS BETWEEN CUSTOMER CLASSES.

Q. What factors other than conventional embedded cost of service analysis should be considered by the Commission in determining the revenue requirement for each class?

A. The Commission has historically considered many other factors, and I believe it should continue to do so. Among the important factors which I think should be considered are:

Stability over time and gradual implementation of changes;
Avoidance of undue discrimination;
Differential risk of different classes of customers;
Differential growth rates among customer classes; and
Differential risk associated with different classes of plant or operating expense;

Q. Do you think that Puget has considered these other factors in its proposed rate spread?

A. No. Mr. Hoff admitted that the Company's proposal to move each class one-third of the way towards the results of the cost of service study was a mechanical application of the results of the study. He specifically stated that no consideration had been given to many of these factors.

Q. Which of these factors do you think are important in this proceeding?

A. I believe all of these factors are important, and in some cases, more important than the results of the cost of service study. For example, Puget has proposed that the secondary general service class receive the smallest rate increase, but this class has been growing much faster than average, and therefore is directly responsible for much of Puget's need for high-cost new resources. Thus, Puget's proposal reflects consideration of the results of an embedded cost of service study to the exclusion of growth and other important factors.

A. Differential Risk Between Customer Classes

Q. What is the concept of including differential risk between customer classes in the evaluation of utility rates?

A. Some classes of customers are riskier for the Company to serve than others. For example, street lighting customers are virtually risk-free. The customers are mostly governmental agencies with taxing authority. The time of day and season of use are completely predictable. The peak demand is precisely known. There are no meters to read, and the costs of accounting and billing are miniscule. This is an example of a very low-risk class. At the opposite end of the spectrum are customers who are extremely sensitive to the business cycle. On Puget's system, these classes would be the primary and high voltage industrial classes. The Company must be prepared to serve a very high level of demand, but runs the risk of having energy sales fall far short of expected levels.

Q. How would differential risk be reflected in a cost allocation study?

A. Applying different risk premiums to different customer classes or subclasses could be done by assuming a different required rate of return for each class. If this were done in computing the revenue requirement for each class, the riskier classes would have higher revenue requirements, and lower revenue:cost ratios than in the Company study, and vice versa for the lower risk classes.

Q. Which are the riskiest customer classes on Puget's system?

A. The riskiest customers are the very large customers on Schedules 46 and 49, and the Resale customers.

Q. What makes these customers more risky than other classes?

A. The sheer size of the customers is the primary factor, since if they leave the system, the Company loses a large amount of revenue and, in the short run, may not be able to shed an equivalent amount of cost. This is exactly what has happened to several of the natural gas utilities in the state, and they have sought (and, in most cases, received) rate increases to their residential and other firm customers to make up the lost margins relative to short-run incremental cost. These large customers could leave the system as a result of economic conditions on their industry, by finding a lower cost power supplier, by installing self-generation, or as a result of regulatory or catastrophic conditions which render their facilities inoperable.

While decoupling may protect Puget's shareholders from lost profits when large customers reduce operations, under decoupling these costs are shifted to the remaining captive customers without any regulatory lag. Without decoupling, the shifts often occur as well, but only after the Commission determines that the associated investment is still appropriately included in rates. In either case, captive ratepayers generally bear all or a substantial part of the burden.

The resale customers are in a slightly different categories. Puget's resale customers, as I understand it, are port districts which resell power to retail customers. As public bodies, they have the option to bypass Puget's system, seeking service from the Bonneville Power Administration, and receive service on such terms as BPA may impose. As a result of such bypass, while the underlying marina loads may be relatively stable, the revenue to Puget from the Port districts may not be.

Q. Are there methods other than risk premiums which can mitigate the risk created by large industrial customers?

A. Yes, another common alternative is requiring large customers to execute long-term contracts with penalties for reducing loads or increasing loads outside of contractually specified boundaries. I will discuss this alternative approach later in my testimony. If the Commission does not impose a rate of return premium on large customers, it should adopt a contractual risk-mitigation strategy.

B. Differential Growth Rates Between Customer Classes

Q. Do different growth rates among customer classes impose different costs on the utility?

A. Yes. Because Puget's revenue requirement growth is driven in part by the cost of securing new energy resources to serve its growing loads, when any class grows in energy demand, it imposes an additional cost on the system.

Q. Which of Puget's customer classes is growing the fastest?

A. The fastest growing portion of Puget's loads are the commercial and industrial classes. The table below shows the percentage growth in kilowatt-hour sales over the period ending in 1990 for each of Puget's major classes:

TOTAL KWH SALES GROWTH 1980 - 1992

Residential	11.3%
Secondary General Service	87.6%
Primary General Service	54.7%
High Voltage	32.6%
Lighting	4.4%
Resale	38.5%
Total System	33.9%

As is evident, the commercial and industrial loads have grown the fastest, but Puget has proposed the smallest rate increase to these classes. The growth of these class is arguably responsible for a disproportionate share of Puget's new higher cost energy resources, which in turn is the driving force behind this rate increase. In fact, it is fairly sobering to consider how large Puget's required rate increases would be if the residential class had grown as quickly as the general service classes.

One form of equity would suggest that the secondary general service class should get the highest increase. Puget's proposal to give the secondary general service class the smallest increase is difficult to defend in light of these differential growth rates. Imposing the largest increase on the residential class, as Puget has proposed, is entirely inconsistent with the concept of having costs be assigned to those who cause them to be incurred.

Q. Have public witnesses recommended that the Commission adopt rates which shift the costs of growth to the classes and consumers causing the growth?

A. Yes, numerous public witnesses have made such suggestions over the years. For example, at the public hearing in the last Periodic Rate Adjustment Mechanism a highly regarded state budget analyst and Olympia city council member (appearing as an individual) recommended that the Commission adopt rates which target growing classes with the costs of growth. The state Growth Management Act generally has redirected the costs of growth imposed on school districts, sewer systems, parks, and fire and police protection to the cause of the growth, rather than to the public generally.

Q. How could differential growth rates be included in the utility cost allocation process?

A. The Seattle City Council implemented a methodology for several years to charge the costs of growth to the responsible classes over a decade ago. The Council was faced with large rate increases for new power resources, rapidly growing high-rise commercial loads, and stagnant residential and industrial loads.

The Seattle Cost of Growth mechanism assigned to each class a three part share of the utility revenue requirement. First, historical revenues were assigned, associated with the level of class energy consumption at the time of the last rate adjustment. Second, a rate increase computed by multiplying class load growth since the last rate adjustment times the marginal cost of new power resources was applied. Finally, the residual required rate increase (to cover inflation and system replacements) was assigned to all classes based on a conventional cost of service methodology. The result was that the large general service class, which was by far the fastest growing class on the Seattle system, received the largest rate increases.

Q. How would you incorporate this type of adjustment into Puget's rates?

A. The various ways this could be done are complex, and were not discussed in detail in either the Rate Design Collaborative or the Rate Design Task Force. My recommendation is that if the Commission wishes to implement a cost of growth based rate spread methodology in this case, that it do so using judgment, rather than algebra. One simple method would be to apportion the rate increase in direct proportion to growth -- if the residential class were responsible for 10% of the growth in kwh sales since the last general rate case, it would be assigned 10% of the rate increase.

If the Commission desires further input on the ways that class growth could be reflected in either rate spread or rate design, it could issue an interlocutory order asking the parties to address alternative methods in further testimony prior to the conclusion of the general rate case.

C. Production Plant Has a Higher Cost of Capital

Q. Is there another kind of differential cost which affects the different classes in different ways, related to the type of property used to provide electric service to the various classes.

A. Yes. Different classes use different mixes of production, transmission, and distribution property. Arguably, each type of property causes different types of financial risk on the utility.

Q. What type of property causes the greatest financial risk on the utility?

A. I think it is clear that production plant causes the greatest type of risk to a utility. Investments in Skagit, Pebble Springs, and WNP-3 are examples of large failed investments which cost ratepayers (and shareholders) millions of dollars for no benefit.

Puget has presented testimony in this proceeding suggesting that purchased power creates additional financial risk for the Company. While I disagree with that testimony to the extent that it suggests a different capital structure is appropriate, I would agree that the higher relative risk associated with production plant exists. I believe this risk is already reflected in the prices at which purchased power is available to Puget.

Q. What about distribution plant? Puget just had a major storm in which millions of dollars of distribution plant was destroyed. Isn't that a type of risk also?

A. Yes, but the risk associated with distribution plant is a relatively minor one for several reasons. First of all, a storm damage adjustment is included in Puget's rates, so that risk is already being reflected in distribution costs. Second, much of the loss was insured. Finally, past experience with major storms suggest that utilities absorb relatively little of the cost of replacing facilities damaged by weather or other acts of God, since they are generally allowed to include the costs of the replacement distribution plant in rate base.

Q. How do the various customer classes vary in the type of utility plant which provides their service?

A. The high voltage class uses a much larger proportion of production and transmission plant than it does distribution plant, since lower-voltage distribution facilities serve only primary and secondary voltage customers; as much as 90% of their bill is associated with power supply costs. Residential customers pay approximately half of their utility bill for relatively risk-free distribution plant, customer accounts, and customer service.

For example, referring to Ms. Lynch's Exhibit 565, Schedule C, the residential class is assigned 66% of the Company's distribution plant, and the High Voltage class is assigned only .7%; the two are assigned 49% and 14% of the production plant respectively.

Q. How would differential risk by type of plant be included in a cost allocation study?

A. Different required rates of return would be applied to different types of property. Instead of computing a cost of service study with a 10% overall rate of return applied to the total rate base assigned to each class, the study would compute class revenue requirements assuming, for example, an 8% rate of return on distribution plant, and a 12% rate of return on production plant. This approach would have allocated costs more closely in line with the risk faced by the utility.

Q. What is the appropriate distinction between "high risk" and "low risk" utility plant?

A. If the Commission were to apply a differential risk element in cost allocation studies, it could use the Average System Cost methodology now used by Puget and BPA for the residential purchase and sale agreement. That methodology separates production costs from other costs in a fairly straightforward manner. A higher rate of return could be applied to those cost elements included in the ASC. Applying this differential rate of return, to the extent it could be quantified with respect to Puget's cost of debt, might even improve the results of the residential and small farm credit for Puget's customers.

VI. RATE SPREAD

Q. If the Commission were to base its rate spread decision strictly on the results of the cost of service study, how would this rate increase be divided?

A. With only the correction to the Company's cost of service study allocating transmission plant as directed by the Commission previously, the residential class would get an average rate increase, the secondary general service and lighting classes would get a smaller than average increase, and the primary, high voltage, and resale classes would get a larger than average increase. However, I am suggesting that other factors should be taken into account as well, and do not recommend a strict application of the results of the cost of service study in apportioning the rate increase.

A. Recommended Parity Ratios

Q. What is the "parity ratio" and what does it measure?

A. The parity ratio, as used by Ms. Lynch, is the ratio of a class' revenues to its revenue requirement at the system average rate of return as determined through the use of the cost of service study.

The parity ratio is one measure of whether a given customer class is contributing as much to revenue as it does to cost, but is limited by the fact that in a typical cost of service study, including Puget's, the revenue requirement is computed at a single rate of return which is not differentiated by the class of service, the type of property used, or the rate of growth.

Q. In light of those shortcomings, is the parity ratio a tool which the Commission can use in evaluating whether a proposed rate is fair?

A. Yes, I believe it is still a useful tool, but unless and until all the other cost and risk differential factors are included in the calculation of the parity ratio, there is no reason to assume that the parity ratio should be 1.0 for all classes. A higher ratio is appropriate for some classes, and a lower ratio for others.

Q. What parity ratios would you recommend be considered if the Commission decides to incorporate the differential risk factors into its rate spread decision?

A. I recommend that the Commission consider these factors outside the cost of service study by adjusting the parity ratios for each class away from unity. I propose target parity ratio for the residential and lighting classes be set at .95, and that the target parity ratios for the Primary, High Voltage, and Resale classes be set at 1.05. The target parity ratio for secondary general service should be set at 1.00, based on risk factors alone, but I propose a parity ratio of 105% based on the differential growth consideration I have discussed and the fact that this is the fastest growing class.

Q. How has Puget proposed that the rate increase be apportioned among the classes?

A. Puget has proposed that the residential class get the highest overall rate increase, in spite of the fact that even its own cost of service study shows that the primary, high voltage, and resale customers are producing a lower rate of return. The table below compares Puget's rate increase proposal, compared with the rates approved in Puget's last general rate proceeding:

Puget Power Average Rates and Proposed Increase

Class	U-89-2688-T Rates	Proposed Rates	Proposed Increase
Residential	$.0555	$.0695	$.0140
Secondary	$.0543	$.0636	$.0093
Primary	$.0398	$.0511	$.0113
High Voltage	$.0276	$.0379	$.0103
Total	$.0496	$.0618	$.0122

Sources: PRAM 1 Rate Design Workpapers, Page 9
Exhibit 571, P. 1

As is evident, Puget's proposal would increase residential rates per kwh by 136% of the amount applied to the High Voltage class, even though the High Voltage customers have the lowest rate of return even under Puget's proposed cost of service study. The revenue to cost ratio for that class is only 83% when transmission costs are allocated in accordance with past Commission directives.

Q. How would you propose the increase be apportioned, if the Commission granted the same level of increase requested by Puget?

A. Based on the $.0122/kwh overall increase the Company has proposed, I would recommend that the primary, high voltage, and resale classes get 150% of the average increase, or $.0183, that the lighting class get 50% of the average increase, or $.0061, and that the remaining increase be assigned equally to the residential and secondary general service classes. This will help to move the primary, high voltage, and resale classes closer to recovering their share of Puget's costs.

Q. If the Commission allows only part of the requested increase, how should it be apportioned?

A. The same method should be used. The overall average increase over U-89-2688-T rates in cents/kwh should be the basis of the increase. Primary, High Voltage, and Resale should be assigned 150% of this average. Lighting should get 50% of this average. The balance should be equally spread to residential and secondary general service.

Q. How does your proposal track the results of the cost of service study and the other factors you have identified?

A. Even without the distribution cost allocation alternative I discuss in Section III(E) of my testimony, the residential class parity ratio is 99%, well above the 95% target parity ratio I discuss below. With any significant change in the allocation of distribution plant similar to that approved for gas utilities, with a portion of the costs allocated on the basis of annual usage, the residential parity ratio would rise above 100%. Therefore the residential class should get a smaller than average increase.

The secondary general service class already has an above-average parity ratio, and one which is above the 105% parity ratio I recommend. I therefore would propose that it get a smaller than average increase. However, it is also a fast-growing class, and should therefore receive a larger increase based on the cost of growth perspective I have presented. Taking these factors together, I recommend that this class receive the same increase as the residential class.

The Primary, High Voltage, and Resale classes pay the lowest rates ont he system. All of these classes are providing significantly below-average parity ratios of 90%, 83%, and 70% at current rates. This alone justifies a higher-than-average increase, even without consideration of the differential risk, differential growth, or differential property type adjustments I have discussed. Each of those adjustments would also increase the revenue requirement for each of these three classes. The target parity ratio for these classes is 105%. I therefore recommend that these three classes all receive a rate increase equal to 150% of the average increase for all of the classes.

The Lighting class is paying far above its cost of service. This class has a target parity ratio of 95%. I recommend that this class get only 50% of the average rate increase.

Q. Have you prepared an exhibit showing how the rate increase would be apportioned among the classes based on your recommendation?

A. Yes, my Exhibit ___(JL-5), Page 3, shows how rates would increase for each class if my recommendation for rate spread is accepted, and the Company's proposed revenue increase over rates from the last general case is approved (which I do not recommend). Under these assumptions, the system average increase would be $.0122/kwh. The rate increase for the Lighting class would be $.0061; for the Primary, High Voltage, and Resale classes, it would be $.01823. For the residential and Secondary General Service classes, the increase would be $.00977/kwh.

B. The Company proposal to move 1/3 of way would be acceptable only if factors other than embedded cost of service are ignored.

Q. Is the Company's proposal to move all classes one-third of the way toward "parity" as measured by its cost of service study reasonable?

A. No, for two reasons. First, the Company study allocates all non-generation-related transmission on a peak demand basis, and as I have already explained, peak demand is only one factor contributing to transmission costs. Second, and perhaps more important, is that embedded cost of service is only one factor in the determination of reasonable rates. The other differential risk and cost factors I have discussed should, in my opinion, also be considered.

C. A Revised Cost of Service Study, Consistent With the Commission's Decision in this Phase, Should be Required Prior to a Final Order in the General Rate Case.

Q. How should the Commission deal with the many different recommendations in this proceeding as to how cost of service should be computed?

A. This phase of the proceeding is scheduled to be completed prior to the filing date for Puget's brief in the general rate proceeding. I recommend that the Commission consider the alternatives which have been presented in terms of the Peak Credit method, transmission costs, and so forth, decide how it believes cost of service should be calculated, and require Puget to file a revised cost of service study prior to filing its brief in the general rate case, incorporating the effect of all non-contested adjustments to the result of operations and such other factors as the Commission may direct. The Commission would then have a much clearer picture of the embedded cost of service based responsibility of all customer classes for Puget's revenue requirement than it has at present, since the Company study does not follow the Commission-approved method for transmission costs.

VII. RATE DESIGN

Q. Why is the design of rates important?

A. The rate design is "where the rubber meets the road" in the utility business. Every one of us has walked into a convenience store, and been able to choose between a "small" soft drink for $.59, and one twice as large for only $.69; in many cases, we may buy the larger size, even though we really only "need" a small drink. Similarly, each of us has purchased vacation airline tickets well in advance for $300 or less, when we certainly would not have paid the full coach fare of $1000 for the same trip. These are examples of rate design strategies designed to produce specific results. The pricing of electricity can also be designed to produce specific results, and great care should be taken in the design of electric rates.

Q. In general, what principles should the Commission consider in designing rates?

A. Rates should be designed to encourage all economic uses of electricity, and to discourage all uneconomic uses. If the end-use to which a kilowatt-hour is put is more valuable than alternative uses of that kilowatt-hour, and more valuable than the incremental cost of producing that kilowatt-hour, the utility should make it available, and the consumer should use it. If the kilowatt-hour is not worth as much as it costs, it should not be sold or used.

Q. What kinds of considerations should go into the design of rates so that all justified usage is encouraged, and uneconomic usage is not?

A. There are many, many factors. The most important, in my opinion, is that the price for incremental usage should be set as close as possible to the long run incremental costs of producing more power. Short-run distortions, such as temporary surplus capacity or insufficiency, wet or dry hydro conditions, or an economic slump or temporary boom in an energy-intensive industry should not be reflected in the prices on which consumers base long-term investment decisions such as the type of heating system to install, the kind of refrigerator to buy, or whether to start or expand a business.

Other important factors include the season in which power is used, the rate at which is it used (demand versus energy), the time of day when it is used, and whether the power being delivered can be interrupted if necessary to serve other customers during peak demand periods.

Q. Do Puget's proposed rates encompass all of these factors?

A. Yes, to a greater or lesser extent. Puget has proposed residential rates and large-user optional rates which reflect some semblance of incremental costs. The Company has proposed more sharply differentiated seasonal rates, and additional options for interruptible rates. The Company considered and rejected most proposals for time of day rates due to the flexibility of the northwest hydroelectric system at meeting diurnal loads. All in all, the Company has proposed improvements to its current rate design in most areas. However, I will make several specific suggestions for improvements.

Q. What has Puget proposed with respect to seasonal rate design?

A. The Company has proposed increasing the seasonal differentiation in its energy charges from 5% to 10%, and proposed sharply differentiating the seasonal demand charges. These steps reflect a consensus on the part of the Rate Design Collaborative that energy costs are somewhat higher in the winter, and that demand-related costs should be assigned predominantly to the winter.

Q. Is this seasonal differentiation appropriate?

A. Yes. The Company's peaking capacity costs are incurred primarily to meet winter peaks and should be recovered primarily in the winter. In addition, both purchased power and natural gas for generating power are more expensive in winter, and therefore winter energy costs are higher.

Q. Are there any problems with the Company's proposed seasonal rates?

A. Yes, there are two concerns that I have. For those schedules with both demand charges and energy charges, the Company has proposed winter demand charges which are about 50% higher than the summer demand charges, and energy charges which are 10% higher than summer energy charges. The net effect, as shown in Mr. Hoff's Exhibit 572, page 16, is that the average rate is about 20% higher in the winter than in the summer is appropriate.

For the non-demand rate Schedule 24, however, the "demand" charge is rolled into the energy charge. Therefore, in order to achieve the same seasonal differentiation where no separate demand charge is imposed, the energy charge must reflect the full 20% seasonal differentiation. This is not as critical for the residential rate schedule, provided that the steeper inversion I propose is accepted, since most residential customers use tailblock power in winter, and the inverted rate is effectively a seasonal rate for them.

A. Residential Rate Design

Q. Turning to the Company's proposed residential rate design, what changes has the Company proposed?

A. Mr. Hoff has proposed the following changes to the rates approved in the last general rate proceeding:

1) An 10% increase in the customer charge
2) A 27% increase to the initial block rate
3) A 29% increase to the end block in summer
4) A 24% increase to the end block in winter
5) An increase in the size of the first block from 600 kwh to 800 kwh

Source: Puget 2/22/90 Rate Insert vs. Ex. 571, P. 17

Q. In general, are these reasonable proposals?

A. In my opinion, the differential between the two rate blocks should be increased consistent with the principle of baseline rates, while Puget's proposal applies the same average increase to both blocks. There remains some controversy over the customer charge, but if the Commission desires to retain the customer charge as a means of collecting the metering and billing costs, Puget's proposal is reasonable.

Q. What change would you recommend to Puget's proposed residential rate?

A. I would recommend that the customer charge and the end block rates proposed by Puget be accepted. To the extent that the Commission approves a lesser overall rate increase for the residential class than Puget has requested, it should be implemented by reducing the rate for the initial block of service. In that manner, the economic pricing policy which Mr. Hoff advocates, and with which I agree, would be preserved, namely that the end block would approximate the marginal cost of serving residential water heat needs. Finally, I recommend that the initial block be retained at 600 kwh, rather than increased to 800 kwh as proposed by Mr. Hoff, but his proposal to eliminate the middle block should be approved.

1. Residential customer charge.

Q. What is the controversy remaining over the customer charge?

A. Puget has computed its proposed customer charge using the basic customer method which the Commission has previously approved, but this still leaves the general issue of whether a customer charge is desirable unresolved. A customer charge is anticompetitive, and to the extent that regulation of public utilities is intended to simulate the market efficiencies which would exist if electricity could be marketed the way gasoline and groceries are marketed, customer charges would not exist (just as they do not exist at gas stations or supermarkets). The customer charge revenue means that the energy charge is lower, and therefore the incentive for customers to pursue conservation and efficiency is reduced by the presence of a customer charge.

Q. Are there examples in the utility industry of how customer charges are not sustainable under conditions of competition?

A. Yes, none of the major interexchange telecommuncations carriers have customer charges. I receive bills from AT&T and MCI for the calls I make. My most recent bill from AT&T was for a total of $1.40. While it may not be particularly economic for AT&T to print and mail a bill, process a check, and keep track of an account for such a small amount, that competitive company has apparently determined that the alternative -- charging me a customer charge every month -- would be worse, because it would mean I would probably <u>never</u> use its service. Rather than impose a customer charge, a discount is offered if I use a large amount of service (WATS) or if I agree to buy a specific minimum amount of service each month (Reach Out America).

Q. Are you advocating the elimination of Puget's customer charge?

A. My preference would be to eliminate the customer charge or propose a disappearing minimum bill like those imposed by Seattle City Light, Washington Water Power (Idaho) or Idaho Power. I have not pressed this argument because the Commission in the past has consistently favored a definition of customer costs which include meter reading and billing costs, and has consistently approved customer charges which reflect those customer costs. The Company's proposed $5.00 customer charge is based on the cost categories the Commission approved in Cause U-89-2688-T. If the Commission wishes to change that policy to encourage additional conservation, promote more efficient pricing, and remove one of the monopolistic features of Puget's rates, it can eliminate the customer charge.

2. Energy Charge blocking

Q. What changes has Puget proposed to the residential rate blocks?

A. Presently, Puget has an initial block of 600 kwh/month, an intermediate block from 601-1000 kwh/month, and a tail block for all usage over 1000 kwh/month. The Company has proposed changing this to a two-block rate, with an initial block of 800 kwh, and a tailblock for all usage over 800 kwh.

Q. Should these changes be approved?

A. The proposal to move to a two-block rate should be approved for the purposes of simplicity. The proposal to increase the size of the first block to 800 kwh should not be approved; if anything, the size of the first block should be reduced, as Puget proposed in its original rate design filing.

Q. What is the advantage of a two-block rate?

A. There are several advantages. First, a two-block rate is simpler than a three-block rate. Second, it may better match the current usage characteristics of Puget's residential customers. Third, it may permit more accurate tracking of Puget's low-cost resources in a low-price block of power.

The history of Puget's rate blocking may be of interest. Prior to Cause U-78-05, the generic/PURPA proceeding, Puget had a two-block rate, with an inversion at 1500 kwh. Mr. Richard Swartzell, then Puget's Vice-President in charge of rates, defended the inversion based solely on the inferior load factor of residential space heat consumers.

A three-block baseline rate was one result of the generic proceeding, wherein the Commission found that an initial block to meet "essential needs" was justified, and specifically found that electric heat was not an "essential need." The definition of a "baseline" rate proposed to the Commission in that proceeding was a block of hydropower priced at hydro cost, with increasing price blocks to reflect the higher cost resources on the system. The Commission at that time adopted the concept of baseline rates.

In its next rate proceeding, Cause U-80-10, Puget implemented a three-block rate, with an initial block of 400 kwh, a second block from 401 kwh to 1500 kwh, and a tailblock for usage above 1500 kwh. Puget increased the rate for the first block by one-half the increase to the tailblock, in order to effectuate the baseline concept in a gradual fashion.

A few years later, in Cause U-83-54, the Commission directed Puget to increase the amount of power provided in the first block to 600 kwh. At that time, the Commission reaffirmed the underlying hydro-based definition of "baseline rates" when it stated:

> Given the fact that low cost hydroelectric power is sufficient to supply an initial 600 kwh block per customer... [U-83-54, 4th Supplemental Order, P. 42]

In Cause U-89-2688-T, the Company proposed, and the Commission approved a reduction in the starting point of the end block from usage over 1500 kwh to usage over 1000 kwh. The primary argument for that was that increased efficiency of new construction and weatherization efforts in existing homes, coupled with a shift of new electrically heated construction from single family homes to almost exclusively multifamily residences, meant that 1000 kwh/month better measured where electric space heat usage begins.

Q. How would you analyze Puget's proposal in this case in light of the past history?

A. I would reject the proposal for an 800 kwh initial block for several reasons. First, Puget does not have sufficient low-cost hydropower to provide that much energy to each residential customer without allocating a disproportionate share of its hydropower to the residential class. Second, 800 kwh is more than the average monthly usage of lights and appliance consumers as shown by Mr. Hoff's Exhibit 572, page 12. The average lights and appliance consumer would have less incentive to conserve than with a smaller headblock. Finally, and most important, however, is an issue that was discussed at length in the Rate Design Collaborative, that a better economic signal is given by applying larger discounts to smaller amounts of power than the Company's revised relatively flat proposal.

Compare, for example, the Company's original proposal in Cause UE-920499 with its revised proposal:

CHANGE IN BLOCK RATES
CAUSE UE-920499 VS. CAUSE UE-921262

Block	UE-920499	UE-921262	Change
Initial Block:	$.04096	$.060277	+47%
Tail Block (Winter):	$.06069	$.074328	+22%

The original proposal had a tailblock which was one and one-half times the level of the headblock; the revised proposal has only a 22% inversion. The point is, that in order to include 800 kwh in the initial block as proposed in the revised proposal in docket UE-921262, compared with only 400-500 kwh in the initial block proposed in Cause UE-920499, the Company must sharply increase the rate for the initial block.

That has the effect of diluting the benefit of a per-customer allocation of hydro benefits. It also provides a smaller conservation incentive to nearly half of the customers on the system at any point in time, since nearly half of Puget's bills are for less than 800 kwh/month. On the other hand, fewer than a quarter of Puget's residential bills are for less than 500 kwh/month, and a smaller initial block (at a lower rate) would result in a better conservation incentive to more customers.

Q. Does the size of the initial block affect the rate to be charged in the tailblock?

A. Not necessarily. Puget has proposed a tailblock based on the marginal cost of serving water heating load. I believe that this tailblock can be implemented regardless of the size of the initial block. However, if a smaller initial block is retained, the rate for the initial block can better reflect the cost of hydropower, and all customers would therefore get a more equal benefit of Puget's low-cost resources.

Q. Have you estimated different impacts on the rate for the initial block of power based on your recommendations?

A. Yes. Exhibit ____(JL-6) computes the rate which would apply to the initial block if it were continued at 600 kwh, and the tailblock were set at Puget's proposed rate. Based on Puget's proposed revenue requirement but my proposed rate spread and rate design, as shown on pages 1-3 of Exhibit ___(JL-6), Puget would have a rate for the initial block of power of only $.053/kwh, compared with the $.06/kwh in Puget's proposal. The tailblock rates would be identical. If the Commission were to grant one-half of Puget's requested increase to the residential class, the headblock could be set at $.0505/kwh, as shown on pages 4-6 of Exhibit ___(JL-6).

Q. Mr. Hoff testified that the Company's proposed tail block is based on the marginal cost of serving water heat loads. In your opinion, is that an appropriate basis for setting the tailblock rate?

A. The present three-block rate can be viewed as having separate lights and appliances, water heat, and space heat blocks. Reducing to two blocks for simplicity should mean either that the tailblock rate is set between the marginal cost of water heat and space heat or at the cost of space heat. I think Mr. Hoff's proposed tailblock is reasonable not so much because I agree with him that the economics of gas space heat are already compelling and should drive the rate design, but because his proposed tailblock ($.074 before the exchange credit; $.066 after the credit) is as large an increase over currently effective rates as I believe is reasonable to impose at one time.

Q. What are the relevant marginal costs for the major residential end uses?

A. Puget recently filed a new Schedule 83, including new avoided cost calculations for the major residential end uses. The long-run (25 year) marginal cost for residential lights and appliances in that filing is $.064/kwh, for water heat is $.074/kwh, and for space heat is $.082/kwh. These include production and transmission costs and losses, but nothing for distribution costs. Public Counsel has expressed concerns to Puget over these calculations, but these figures are reasonable proxies for the purposes for which they are being used in this proceeding.

Mr. Hoff's proposed tailblock is equal to the water heat avoided cost <u>prior to</u> the effect of the residential exchange credit, Schedule 94. After the effect of the exchange credit, Mr. Hoff's proposed tailblock is $.065/kwh, or about 10% below the marginal cost of serving water heat and 20% below the marginal cost of serving space heat. Later in my testimony I will propose a hook-up charge for new residential space and water heat customers which will help recover this difference between the tailblock rate and the marginal cost of serving space and water heat, which helps reduce the burden on existing customers with electric heat.

Q. Is there a better cost basis for the initial block of Puget's rate design than the lights and appliances avoided cost?

A. Yes, I believe that the actual cost of Puget's low-cost resources, plus an average amount for distribution costs, is an appropriate way to price the initial block of power.

Q. Have you made an estimate of this cost?

A. The average cost of Puget's hydropower resources is about $.015/kwh. The average cost of distributing power to residential customers is about $.025/kwh. Therefore, an appropriate cost-based initial block rate is $.04/kwh, which is about the initial block rate the Company proposed in Cause UE-920499.

Q. Can Puget still provide 600 kwh/month to its residential customers from its hydroelectric resources?

A. No. The amount of available hydropower on Puget's system has not increased since Cause U-83-54, but the number of residential customers has increased by more than 25%. Puget's residential customers use about 48% of the Company's total energy. The Company has 8 billion kwh/year of hydropower available. Assigning 48% of that to the residential class would make 4 billion kwh available for residential customers. The Company's total power sales to the initial 600 kwh block of power for the residential class is 4.4 billion kwh/year. It would therefore appear that the Company could actually provide only about 460 kwh/month in the initial block before exhausting the residential class share of the available supply of hydropower.

Q. Are there reasons to keep the initial block at 600 kwh in spite of the fact that some thermal energy would need to be melded into this block?

A. Yes. Both Washington Water Power and Pacific Power provide 600 kwh in their initial rate block. Maintaining Puget's initial block at 600 kwh would maintain consistency in the initial block allowance statewide.

Q. Does Puget have other low-cost resources which can be used to supplement the available hydropower to make up a block of 600 kwh/month per customer?

A. The next lowest cost major resource on the system is Colstrip 1&2, with a cost/kwh of about $.02/kwh. If this was added to the available hydropower, Puget would have enough to offer each residential customer about 600 kwh/month without affecting the amount reserved for other customer classes.

3. Residential Rate Design Summary.

Q. Please summarize your recommendations with respect to residential rate design?

A. First, as previously stated, I propose that the residential class be assigned about 80% of the system average rate increase, compared with Puget's proposal that residential customers again receive an above-average rate hike.

Within that revenue requirement, I recommend that the Company's proposed customer charge of $5.00 be approved. I recommend that the Company's proposed two-block rate be approved, but that the initial block be kept at the current level of 600 kwh. The tailblock rates should be set at the level Puget has proposed. The rate for the initial block should be increased only as much as is necessary to produce the allowed revenue requirement. The rate proposed in Cause UE-920499 of $.04096/kwh is sufficient to cover the low-cost resources in that block plus distribution costs. To the extent that the Commission ultimately adopts an overall rate increase which is smaller than Puget has proposed, it should be possible to hold down the head block at or below the level approved in the PRAM II order as shown on Page 6 of my exhibit ___(JL-9). If these steps are taken, every residential customer will receive a smaller bill than if Puget's proposed rates were approved, even though the incentive for conservation embodied in Puget's proposed tailblock will be undiminished.

B. Secondary General Service

Q. What are the major issues in this proceeding regarding rates for the Secondary General Service class?

A. The most important change Puget has proposed is dividing this class into three separately tariffed subclasses. Puget has also proposed rates more sharply differentiated by season, and a shift of cost recovery for the larger customers towards the demand charge.

Q. Begin by discussing the proposed breakup of the current Schedule 24 into three smaller rate schedules.

A. The current Schedule 24 includes everything from espresso stands to high-rise office buildings. It is a declining block rate design, which allows small, non-demand customers to be included in the same schedule as large, demand-metered customers. Puget's proposal to separately tariff the non-demand customers is reasonable. The Company's proposal to create a separate class of the largest customers is not necessary.

Q. What is the benefit of creating a separate schedule for non-demand metered customers?

A. It allows the elimination of the current declining block rate, which has the effect of favoring larger customers over smaller customers if both have above-average load factors and favoring smaller customers over larger ones if both have below-average load factors. For example, if one shopping mall consisted of separately metered shops with a total load factor of 60%, and a large department store with an identical 60% load factor was on a single meter nearby, Puget's current tariff would charge the large department store significantly less than the individually metered smaller shops.

Q. Why is it unnecessary to create a separate schedule for the larger demand-metered customers, Puget's proposed Schedule 26?

A. The Company has proposed lower rates for the larger customers, but even the Company's cost of service study shows that the smaller customer group, the proposed Schedule 25, is paying a higher rate of return than Schedule 26 [Exhibit 4, Summary 1, P. 2, Line 27]. By applying the same rates to these two classes, the rate of return for both will be more equal. There appears to be no cost justification provided for having a lower rate for the larger customers.

This Commission has adopted the declining block rate standard of PURPA, which states:

> The energy component of a rate, or the amount attributable to the endrgy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility of providing electric utility to such class which costs are attributable to such energy component decrease as such consumption increases during such period.

In my opinion, Puget has not demonstrated that the condition required by the PURPA standard -- that energy costs are decreasing as energy use increases -- exists for this class of customers. The results of Puget's cost of service study specifically suggest otherwise; the large customers now benefitting from the declining block rate are paying a lower rate of return than the smaller customers.

Q. What do you recommend with respect to the proposed Schedule 26, for the largest customers?

A. I recommend that it be rejected. These customers should be served on the proposed Schedule 25.

Q. Within Puget's proposed schedule 25 there is also a declining block rate. Mr. Hoff indicated that this was necessary to protect some customers from inordinate rate impacts. Do you agree?

A. No. The problem Mr. Hoff raised is very real, that some customers over 50 kw demand with particularly poor load factors, would pay very high bills if a flat demand and energy charge were applied to them. An example would be a municipal park with outdoor field lighting which is used only 3 hours a night, four nights a week. That usage -- about 50 hours/month, would amount to a load factor of less than 10%, and the demand charge would be more than half of the electric bill. There are much better ways to deal with this problem than through the declining block rate design proposed by Mr. Hoff. These include applying time-of-day demand charges only during the system peak hours, using load-factor blocks in the rates, or applying an energy-constrained demand charge.

The first option would charge the low load factor customer for demand at the same rate as other customers, but only during the hours when the system peak is most likely to occur. If the customers's poor load factor were due to high usage during an off-peak period, they would pay a much lower "facility charge" based on the customer-specific transformer which serves them. I am aware of some utilities which do this. An example of such a rate would be as follows:

Customer Charge:	$8.00/month
On-peak Demand, 7:00 A.M. - 12:00 Noon	$4.00/kw
Demand in Excess of On-Peak Demand:	$2.00/kw
Energy Charge:	$.04/kwh

The second option would be a different type of rate design, called "load factor blocks" which still looks like a declining block rate, but where the entire demand charge is rolled into the energy charge. An example would be:

First 200 kwh/kw	$.06
Additional kwh/kw:	$.04

In this type of rate design approach, there should be no separately stated demand charge at all. Practically speaking, load factor blocking works the same as a $4.00/kw demand charge and a $.04/kwh energy charge, except that any customer with less than 200 kwh/kw (a 28% load factor) would pay only a pro-rata demand charge. The only problem with using load factor blocks as an alternative is that it looks like a declining block rate.

The third alternative would be specific language specifying the maximum rate per kwh that the demand charge can be. Based on the above example, the tariff would read

Demand Charge: $4.00/kw but not to exceed $.02/kwh

Any of these options would permit the elimination of the declining block rate design which Puget has proposed for Schedule 25. I prefer the energy-constrained demand charge approach.

Q. Should customers with poor load factors pay the same demand charges as customers with high load factors?

A. Generally no, unless the customer imposes its highest individual peak demand at the time of the system peak. There are two components to the demand-related costs incurred to serve a customer. First, there are the customer-specific distribution plant facilities needed to serve an individual customer. These may include primary distribution lines and transformers. The costs are usually relatively small, but they must be incurred even if the customer uses power only one hour per year. The second category are production and transmission demand-related costs associated with installing peaking generating plants and overbuilding the transmission to meet peak loads which exceed off-peak loads. A low-load factor customer only uses these production and transmission facilities part of the time, and they can be used by other customers at other times. If the individual customer's individual peak is not at the time of the system peak, they should not have to pay the full cost of these facilities. On the other hand, a high load factor customers uses production and transmission facilities more or less continuously, and should pay the full costs of the capacity which can really only serve their own needs.

Q. Can you give an illustrative example of a customer with a low load factor and an individual peak demand which occurs off-peak?

A. The municipal park with outdoor field lighting discussed earlier is an extreme, but realistic example. Field lighting is almost by definition an off-peak load. Puget's peak usually occurs in the morning, and field lighting is usually used in the evening. When it gets <u>extremely</u> cold (for example, the highest 12 peak load hours of the year), the outdoor athletic events are usually cancelled anyway. As one school superintendent once said, "I know my field lights are off-peak, because when the lights are on, nobody's home using power -- they're all at the game!"

Q. Is the seasonality of the proposed Schedule 24 and Schedule 25 rates appropriate?

A. No, not for Schedule 24. As I mentioned at the beginning of this section, Puget has applied a seasonal demand charge to Schedule 25, which when combined with the seasonal energy charge, works out to an effective 20% seasonal differential. Puget has proposed only a 10% seasonal differential for Schedule 24, where the demand charge is rolled into the energy charge. The energy rate in Schedule 24 needs to be more sharply seasonally differentiated to equal the 20% rate differential included in the other general service rate schedules.

Q. What is your recommendation with respect to the proposed Schedule 29 irrigation rate?

A. This rate schedule should be eliminated. As shown in Puget's cost of service study, the irrigators are producing far less revenue than the cost of service, in spite of the fact that they are allocated essentially zero production and transmission demand cost. At any reasonable allocation of production and transmission demand-related costs, the results would be even worse. The proposed Schedule 29 rate is lower than the proposed Schedule 25 rate in both winter and summer. There is no economic justification for discriminating in favor of irrigators, who are likely to be more expensive to serve, simply because they are located in rural areas with higher-than-average distribution costs. Irrigators are being heavily subsidized by other customer classes.

Q. How should Puget's irrigators be served?

A. They should be served on the general service rate schedules. With the increased seasonal differentiation on those schedules that Puget has proposed and I have recommended, irrigators will pay much lower average rates per kwh than other customers on these schedules, since they use power primarily in the summer months.

Q. What about the BPA irrigation discount. How would it be provided to irrigators if the Schedule 29 rate were eliminated?

A. Many participants in the BPA rate proceeding are recommending elimination of the irrigation discount, since it encourages extra power usage at the expense of decreasing the amount of power available to BPA as a result of water being withdrawn from the river. If the discount is continued, it can be flowed through the Schedule 25 (secondary) or Schedule 31 (primary) rates, just as it is now flowed through the Schedule 29 and Schedule 35 rates. Alternatively, the rates for Schedule 29 and Schedule 35 could be set equal to those on Schedules 25 and 31, and the tariff kept "separate but equal" rather than eliminated.

C. Primary General Service

Q. Do you have any recommendations with regard to the Company's Schedule 31 Primary General Service?

A. The proposed rate design is reasonable and should be approved. The overall level of rates is far too low, as shown in my exhibits ___(JL-4) and ___(JL-5), but the general approach, with demand charges 50% higher in winter than in summer, and energy charges 10% higher in winter than in summer, is a reasonable approach. I have addressed the low overall rate levels Puget has proposed for this class in the cost of service and rate spread sections of my testimony, where I recommend that this class receive an increase per kwh which is 150% of the system average increase per kwh.

Q. Turning to Schedule 35, primary irrigation service, are your recommendations here the same as for Schedule 29, secondary irrigation service?

A. Yes, as stated above with respect to the secondary voltage irrigation Schedule 29, the irrigation schedules should be eliminated. Irrigation customers who require primary voltage should be served on Schedule 31, and will benefit from the increased interruptibility which Puget has proposed for that schedule. Those which do not need primary voltage should be served on Schedule 25. The proposed rate for Schedule 35 is lower than that for Schedule 31 in both winter and summer. There is no economic basis for discriminating in favor of irrigation customers, when in fact, their wide geographic dispersion makes them more expensive to serve, not less.

D. High Voltage Service

Q. What is the primary issue with respect to Puget's High Voltage customers?

A. The primary problem is the level of rates, not the design of rates. As shown in Puget's Exhibit 5, these customers are paying 83% or less of their allocated revenue requirement. Puget has proposed a below-average increase for this class. The proposed rate is no higher than the raw cost of power; there is no contribution to cover abandoned nuclear plant costs, delivery costs, or administrative costs of the Company. The most important thing is that the Commission assign this class a greater-than-average rate increase, measured on a cents per kwh basis.

VIII. INTERRUPTIBLE RATES

Q. Puget has proposed four different new interruptible rate schedules, and has proposed freezing the Schedule 43 interruptible rate for all-electric schools. Should these changes be approved?

A. Yes, all of the proposed interruptible rate changes should be approved, including the residential water heat interruptible rate schedule proposed in Cause UE-920499, but withdrawn by the Company in the general rate filing. All of these were discussed at length by the Rate Design Collaborative, and all will help to control rising costs in the future.

A. Schedule 43 - All-Electric Schools

Q. Begin with Schedule 43, for all-electric schools. Why should this rate be frozen?

A. From a rate design perspective alone, the rate should be eliminated. The rate is not cost-effective, the revenues do not cover costs, and the restrictions on interruption -- in the evening hours only -- do not match the period when Puget's peak demand most often occurs, which is in the morning. In light of the number of schools which take advantage of this rate, and the difficult financial condition of schools, Puget's proposal to freeze the rate is more appropriate.

Q. Are there any changes which should be made to Schedule 43?

A. Yes. Ideally, the customers should be interruptible in the morning as well as the evening. That is simply not practical for schools. For that reason, the average rate on this schedule is and should be higher than for other interruptible customers.

The current schedule availability is limited to "any permanently located school whose total water heating and space conditioning requirements are supplied electrically.". This condition should be removed, so that the schools presently on this schedule can utilize other heating sources. One way that schools should be allowed to deal with higher rates is by converting water heating, space heating, and cooking to gas. Assuming 80% conversion efficiency, Washington Natural Gas firm service rates proposed in Cause UG-920840 are about one-third lower than those proposed for Schedule 43. That flexibility will allow schools to better deal with Puget's increasing electric rates as well as to reduce uneconomic loads on Puget's system.

B. Interruptible residential water heat rate

Q. Turn now to the interruptible water heat rate. Why do you say this rate should be approved, even though Puget has asked that it be withdrawn based on testimony that the costs were understated in the Company's exhibit in Cause UE-920499?

A. The Company analysis assumed a $300 cost per control point. Based on that estimate, the Company concluded the program was not viable. This is as much as three times the cost estimate made by other entities, including the cost of retrofitting radio controllers. A more appropriate approach would be to install controllers at the time of new construction. If this is offered as part of the electric space and water heat hook-up charge I propose later in my testimony, and builders are given a $50 credit against the hook-up charge at the time of construction, the cost of installation would be much lower.

In addition, if the load control credit is paid only during the four month period December-March when interruption is likely, and is paid at a rate of $10/month for four months rather than $5/month for twelve months as originally proposed by Puget, the cost to Puget of the incentive for customers to participate would be smaller, while the compensation to the consumer during the high-bill months when interruption is likely would be increased.

Q. Are there other changes which should be considered?

A. Yes, the program should be made available on a retrofit basis to customers on a voluntary basis. The customer would get the same $50 credit as new construction, but would have to bear the installation costs directly. Also, electric hot tubs with water heaters over 4 kw should be eligible for the program. I expect that many electric hot tub owners would be interested in such a program. Unfortunately, Mr. Swofford, Mr. Lehenbauer, and I all own super-efficient hot tubs, with only 1.5 kw heating elements, so we would not be eligible.

C. Schedule 36 - Secondary Voltage; Schedule 38 - Primary Voltage; Schedule 39 High Voltage

Q. Should Puget's revised schedules 36, 38, and 39, which offer interruptible rates to commercial customers, be approved?

A. Yes. The Company revised the Schedules from Cause UE-920499 to greatly reduce the customer charge. I felt the high initial charges to participate in the program would unnecessarily dissuade customers from participating. The revised program is more likely to attract participants. These schedules offer real potential for capacity savings to the Company and they should be approved.

Q. How do the capacity credits in these schedules compare with the Company's cost of peaking capacity?

A. The interruption credits are quite a bit lower that the "peak" capacity cost used by the Company in the Peak Credit methodology in this case, which in turn is based on half the cost of a combustion turbine peaking unit. If the Company is able to secure large blocks of interruptible load at the level of credit being offered, then we will know that interruptibility is a low-cost source of peaking capacity. If these rates are successful, Puget should be expected to revise the peak credit formula accordingly in the future to reduce the percentage of generating plant cost which is treated as peak-related.

IX. LARGE USER MARGINAL COST RATES

Q. Should Puget's proposed Schedules 30 and 48, the Large User Marginal Cost rates, be approved?

A. Not in the present form. While rates for large users should be priced much closer to marginal cost, and the proposed rate design is a creative way to approach that problem, the proposed rates will not produce the desired results.

Either the rates should be mandatory for all customers, or they should not be offered. The proposed voluntary rate will be attractive to any customer which is planning to reduce their load and/or their operations, but will be shunned by any customer planning to increase operations faster than their usage has increased in the past.

The Company's proposal to use a linear regression model to determine the base period use means that a customer which has been growing in the past (such as Microsoft) will be <u>assumed</u> to continue growing at the same rate in the future. Given the explosive past growth of some customers, that is simply implausible, as Mr. Hoff agreed during cross-examination.

Q. What alternatives were discussed in the Rate Design Collaborative for this type of rate?

A. One alternative which was discussed was a mandatory rate, with the initial block set at 75% of the actual metered usage for the same period three years earlier. That simpler approach would eliminate the bias in favor of growing customers which Puget's proposed approach contains.

Q. What should the Commission order?

A. Either the rate should be made mandatory for all customers, and the regression analysis eliminated in favor of a strict historical baseline, or the proposal should be rejected and referred back to the Rate Design Collaborative or other interested parties for additional analysis.

X. OTHER ISSUES

Q. What other issues should the Commission address in this proceeding?

A. I will briefly discuss two major and one minor issues. The major issues are hook-up charges for new residential electric heat loads and advance notice requirements for large changes in load by major customers. The minor issues is an apparent omission from the lighting schedules.

A. Space/Water Heat Hook-up charge / Line Extension Policy

Q. What do you propose with respect to imposing a separate hook-up charge for new electric space and water heating connections?

A. I propose a fee of $200/kw for all new residential electric space and water heating connections to Puget's system. This fee would apply based on the amount of installed load, so that a home with 10 kw of installed electric space heat and a 4 kw electric water heater would be assessed a hook-up charge of $2800. A heat pump with a maximum demand of 5 kw would be assessed $1,000.

Q. What is the purpose of this proposed hook-up charge?

A. There are several purposes, all of which are important.

First, it will partially compensate Puget for the unrecovered cost of serving these new loads, reducing the burden which must be borne by other customers through rate increases.

Second, it will encourage builders choosing electric heat to install no more than the minimum required level of space and water heat, thereby reducing Puget's peak load.

Third, it will encourage builders to develop building lots closer to existing gas mains, and to select natural gas for space and water heat rather than electricity. This is societally cost-effective in many cases, and is consistent with the Washington State Energy Strategy.

Q. Do you propose to apply this only to residential buildings?

A. Yes, at this time. Electric heat in commercial buildings is most often in the form of heat pumps which are installed to provide both heating and cooling. Cooling is usually the more important load, and therefore a hook-up charge based on the installed heating capacity may not make sense. Where heating is the primary energy use, such as in warehouse stores, natural gas is already the overwhelming fuel choice.

Q. Very few of the new homes built in Puget's service territory now have electric heat. Will your proposed hook-up fee actually make a difference?

A. For single family homes, nearly all the new construction uses natural gas <u>where it is available</u>. Many homes are built outside of the area where gas is available, and those typically have electric heat. In addition, multifamily construction is the fastest growing part of Puget's residential customer base, and nearly all multifamily units have electric space and water heat. In the five year period ending 1990, the growth rate for single family homes was 2.7%, while that for the apartment/condominium category was 7.6%

[Puget Power Factbook, 1990, P. 9] The typical new apartment consumes more electricity than the typical new single family home, simply because electricity typically provides all of the space heat, water heat, lights, and appliance energy in the multifamily sector.

Q. How will your proposed hook-up charge affect builders?

A. Presently, builders may choose electricity rather than natural gas for many reasons. First, it is cheaper to install electric heating equipment. Second, since the multifamily building owner does not pay the energy bills there is little incentive for the owner to invest to reduce energy bills by installing gas. The owner does pay for maintenance, however, and gas heating appliances require higher maintenance than electric heat. Third, the cost of extending gas service may be considerable in some locations. All of these factors bias the market in favor of electric heat, regardless of the societal cost-effectiveness of gas.

Q. How would your proposal address these factors?

A. By increasing the cost of choosing electric space and water heat, my proposal would more than offset the current cost advantage of installing electricity. Second, for the multifamily building owner, it may well make it cheaper, from a first cost perspective, to install gas heat, and thereby overcome the owner's current cost incentive to choose electric heat. Finally, it is likely that for many developers, the hook-up charge associated with installing electric heat would equal or exceed the cost of paying for a gas main extension to the property.

1. Present line extension policy is non-fuel specific.

Q. Does Puget's current line extension policy encourage the installation of electric heat?

A. No, not for residential customers. The current line extension policy allows a fixed amount of line extension at no cost, and the developer must pay any amount above that level. In Cause U-89-2688-T, Puget proposed a higher line extension allowance for electric heat customers, but the Commission denied it.

Q. Why, then, do developers continue to choose electric heat?

A. Electricity is essential for any new home. Gas is optional, since all of the same end-uses can be served with electricity. There are additional costs associated with installing gas, including both extending the gas mains and installing (more expensive) gas appliances.

This incentive to choose electric heat is partially offset by the Washington State Energy Code, which requires additional insulation in electrically heated homes. In addition, nearly all single family homes located near gas mains are constructed with gas space and water heat in response to consumer preferences. The primary problem is with multifamily construction and with those single family developments in outlying areas.

2. Washington State Energy Strategy

Q. What is the policy of the state, as enunciated in the Washington State Energy Strategy, with respect to encouraging the choice of natural gas over electric space and water heat?

A. The Strategy endorses measures to provide gas service to more areas of the state and to more new buildings than current policies achieve. Exhibit ___(JL-7) is an excerpt from the Strategy addressing this issue. Some of the direction in the Strategy is to this Commission to modify line extension policies to allow gas utilities to serve additional customers. In my opinion, my proposal is the best way to achieve this goal of the Strategy, without placing unnecessary burdens on existing electric or gas customers.

Q. How does increasing the hook-up charge for electric space and water heat achieve the goal of the Strategy for modifying gas line extension practices?

A. Developers will compare the total cost of installing electric appliances to the total cost of installing gas appliances. The "total cost" will include any line extension and hook-up charges for either gas or electric service.

Assume two different examples. One is a single family housing development, and the other is a multifamily apartment complex. In the first case, the developer (responding to market desires of buyers) would prefer to install gas, even though it is more expensive, but faces a line extension charge from the gas company. In the second, the development is adjacent to a gas line, but the developer wants to avoid higher construction costs associated with installing gas appliances. In both cases, my proposed hook-up charge will encourage the builder to install gas.

Q. Please begin with the example of the single family home developer. How would your proposed hook-up charge affect the choice between electric and gas heat?

A. Assume a single family development of 20 homes, located a half-mile or more from the nearest gas main. While the homes are close together, and individually would qualify for free installation of distribution mains within the development, and a free <u>service</u> extension to each home, the developer is still faced with the cost of a distribution main extension <u>to the perimeter</u> of the development. Under the Washington Natural Gas distribution main extension policy, the developer would face a charge of $30,000 to run gas to his development, or about $1500 per house. In addition, installing gas appliances costs an extra $1000/house compared with installing electric heat. The total cost is $2,500 per house.

The alternative is to build the homes to the electric standards of the Washington State Energy Code, which costs about $1500 extra per unit, and install electric space and water heat. If the builder chooses the electric option, it will be reimbursed $900 per unit by Puget under the terms of the Code legislation, for a net cost of $600/unit to the developer.

The difference is substantial -- the developer is looking at a $30,000 additional cost to extend gas to the development, plus $20,000 to install gas appliances, for a cost of $50,000 for the development. If the developer chooses electric space and water heat, it faces $30,000 of additional construction costs to meet the electric code, but will receive $18,000 in builder incentive payments from Puget, for a net additional cost of $12,000. The builder is $38,000 ahead choosing the electric option.

Q. How would your proposed hook-up charge change the builder's incentives?

A. Assume that under the electric option, each home would have 10 kw of electric space heat, and 4 kw electric water heaters, for a total of 14 kw. Under my proposal, the developer would have to pay $2,800 per house for the electric hook-up charge, or $56,000 for the development. Added to the net cost of the electric option of $12,000 (after the builder incentive payment), the electric option would cost the developer a total of $68,000. Since the cost of the gas option, including both the line extension and the appliance installation cost, is only $50,000, and the builder's customers prefer gas anyway, the builder most likely will pay for the gas line extension, install gas appliances, and achieve the goal of the State Energy Strategy.

Q. Please describe how your proposal would affect the multifamily developer, compared with the current system of hook-up policies?

A. I assume that the apartment developer is located in an area where gas is available without a line extension fee imposed by the gas utility, but the developer still chooses to install electric heat because of the lower first costs and lower maintenance costs.

In this case, the cost per unit of meeting the Washington State Energy Code for electric heat adds $700/unit to the developer's construction costs, and that $500/unit of that is paid by Puget under the terms of the Energy Code legislation. Installing gas appliances adds $1000/unit above the cost of electric space and water heat, and building the apartment complex to meet the more stringent fire code requirements where combustion appliances are used adds $500/unit to the cost of the development. Thus, the developer is faced with a net cost of $20,000 ($200/unit x 100 units) to install electric heat, or $150,000 ($1,500/unit x 100 units) to install gas heat. Given the fact that gas appliances will require more maintenance, there is little doubt about how the builder will proceed, and nearly all multifamily developments being built at this time use electric heat.

Q. How would your proposal change the economics of this project?

A. Everything would stay the same, except that the developer would also have to pay $200/kw for the space and water heating load under the electric option. Assume that each apartment unit would have 5 kw of electric space heat, plus a 4 kw electric water heater, for a total installed load of 9 kw. The total installed space and water heat load for the complex would be 900 kw, and the developer would be assessed a $180,000 hook-up fee by Puget. The net result would be a $200,000 cost of the electric option, versus $150,000 for the gas option, and the developer would very likely choose the gas option. Doing so would help achieve one of the goals of the Washington State Energy Strategy.

3. Gas Line Extension Policy is Not the Problem.

Q. Why not just change the gas company line extension policy to provide more economical connections for developers?

A. The problem is not the gas line extension policy. One of the major issues which I expect will be before the Commission in the current Washington Natural Gas rate proceeding is that many of the line extensions that Company has already installed are uneconomic. The combination of high construction costs for gas lines, plus low sales of gas per customer in new energy-efficient homes, means that the gas utility loses money on many of its new customers. In effect, for the gas utility, the marginal cost of service is very close to the average rates, and extending lines further than permitted under the current line extension policy would cause further income erosion and/or rate increases for gas ratepayers.

Q. How is your proposal a more creative way to deal with the problem?

A. My proposal would increase the cost of electric space and water heating connections closer to the cost of providing that service. This will fairly apportion electric system costs to new customers, while holding down bills for current customers. Puget's rates (even its proposed rates) are below marginal cost for space and water heat customers. As I discuss in my testimony on residential rate design, Mr. Hoff's proposed end-block is below the full marginal cost of serving residential water heat customers (including distribution costs), and far below the marginal cost of serving residential space heat customers. Adding a hook-up fee for these end-uses will bring the total revenue for service more in line with the incremental costs.

The alternative, changing the gas line extension policy to provide cheaper gas line extensions, will cause new gas customers to be provided service below cost and would force rates up for existing customers who are already paying the full cost of their own service.

4. Hook-up Fee is Cost-Based

Q. What are some of the cost-justifications for imposing a $200/kw hook up fee on new space and water heating connections?

A. There are many justifications for this type of hook-up charge. First, just looking at the need to increase transmission peaking capacity across the Cascades to reinforce the Puget Sound area, Bonneville found that the costs would be on the order of $250 million for 2000 MW, or about $125/kw. That transmission is needed only if peak loads continue to increase, and the $250 million cost is only the incremental cost of upgrading the capacity of the existing transmission system.

Second, the cost of new peaking resources is far higher than the proposed hook-up charge. Ms. Lynch's Exhibit 5 was based on a $400/kw cost for a simple cycle combustion turbine; these would be needed only to meet increases in peak demand. Eliminating the space and water heating loads would reduce Puget's coincident peak demands substantially, and thus avoid this type of cost. Since Ms. Lynch took one-half of this cost, about $200/kw, as the cost of peaking capacity, the proposed hook-up charge is cost-based.

Third, Puget's overall rates for space and water heating service are lower than the incremental costs to provide that service. As I discussed earlier, new space heat customers will use power costing $.082/kwh (plus distribution costs) and under Puget's proposed Schedule 7 and Schedule 94 rates will pay only $.066/kwh. This discount biases them in favor of installing electric heat. The $200/kw hook-up fee helps to recover the difference between the cost of service and the rate. By both discouraging these loads, and by capturing an additional contribution when they do occur, Puget would bring its costs and rates better into balance with each other. It was exactly this type of calculation which Mason County PUD #3 used in deciding to impose a $2000/house hook-up fee on new homes not meeting the model conservation standards.

5. Other utilities have implemented hook-up charges.

Q. Have other electric utilities implemented hook-up charges which have the effect of discouraging electric space and water heat?

A. Yes, quite a few, including Mason PUD #3, Clallam PUD, Snohomish PUD, and the city of Canby, Oregon. Each has used a different approach. I presented a paper on the subject of utility hook-up charges at the Second International Conference on Energy Consulting in Graz, Austria in 1991. The paper is entitled "Utility Connection Charges and Credits: Stepping Up the Rate of Energy Efficiency Implementation." In preparing that paper, I evaluated a number of different options for utility connection charges to encourage efficiency. Of the options I have reviewed, I believe that the method I have proposed here will be the most effective.

B. Advance notice of load changes

Q. What type of notice are Puget's large customers required to give before changing the level of their load?

A. The Company's tariffs do not provide any notice requirement. As a practical matter, a customer cannot increase load above the level which existing installed distribution facilities can provide without notice to the Company, but there is no notice required at all for reductions in load.

Q. Does this pose a risk to Puget and its other customers?

A. Yes. If a large new load were to apply for service on short notice, Puget could have its load/resource balance destabilized. Similarly, if a large customer were to leave the system on short notice, Puget could be left with a long-term resource, and no economic market for the power.

Q. Is this a realistic scenario for Puget?

A. Yes, I believe so. First, there are three direct service industrial (DSI) customers in Puget's service territory (Intalco Aluminum, Georgia Pacific, and Port Townsend Paper Company). Their contracts with the Bonneville Power Administration expire on July 1, 2001, and it is entirely possible that they may apply for service from Puget on relatively short notice. The usual need for advance notice -- construction of transmission and distribution facilities -- would not apply to these customers, since the power delivery facilities are already installed. Furthermore, under Puget's current tariffs, these customers could apply for service, forcing Puget to acquire high-cost resources to serve them, and then they might subsequently secure power at lower cost from another source and leave Puget's system on short notice.

Q. Have major industrial customers imposed this type of uncertainty on Northwest utilities?

A. Yes, the DSIs have imposed highly erratic loads on the Bonneville Power Admininstration over the past decade. Industrial gas users have come and gone from the natural gas utility systems on short notice, first when rapidly changing oil prices caused them to choose alternative fuels based on market conditions, and more recently when they have been afforded the opportunity to bypass the utility system. One industrial gas customer, Inland Empire Paper, continued to rely on the Washington Water Power Company for gas service during periods of curtailment of its primary supply even after it bypassed the WWP system.

Q. How can this type of short-notice erratic change in electric revenue be dealt with in tariffs?

A. Many utilities use tariffs requiring a certain period of advance notice prior to changes in contract demand levels. The Washington gas utilities have begun using this type of contract for gas transportation service.

Q. Would an advance notice requirement help to offset the increased risk of serving large industrial customers which you discussed in an earlier section of your testimony where you addressed the cost of service and rate spread implications of large industrial customers?

A. Yes. If the Commission adopts the risk premium in the rate of return which I recommend for large industrial customers, it would address the concern I am raising here. If it does not assign a higher rate of return requirement to large customers, however, it should mitigate the risk these customers pose to other consumers by imposing advance notice requirements.

Q. What type of advance notice should be required from large customers?

A. I believe that the advance notice for very large increases or decreases in load should be related to the amount of time that Puget requires to secure additional power supplies or dispose of excess supplies. Puget's contract with the Bonneville Power Administration requires the Company to give seven years notice of a change in firm power demand. That is the longest notice period which I think is reasonable.

Q. Is the BPA contract a reasonable yardstick to use for advance notice?

A. I believe it is. The regional power act gave BPA the obligation to provide Puget with power to meet increased loads, and Puget entered into a contract with BPA under the Act.

Q. Under what circumstances is shorter notice than the seven years in the BPA appropriate?

A. A customer wanting to make a smaller change in their level of power usage should be allowed to give shorter notice. I would propose that three years advance notice be required for any change in contract demand in excess of 10 megawatts, and five years advance notice for any change in contract demand in excess of 30 megawatts, on the theory that Puget could meet that size change in loads with a non-BPA power supply source. I propose that a change in loads of more than 50 megawatts would require the full seven years notice.

Q. How should this be implemented following this case?

A. All customers served on Schedules 46, and 49 (and Schedules 48 and 39 if they are approved) should be required to execute long term contracts as a condition of service on those schedules. The contracts should provide for minimum notice of changes in demand of 10 megawatts or more as I have described. In the case of decreases in load, the contracts should provide for payment of the tariff demand charge for the full level of contract demand if a customer reduces usage prior to the effective date of the change pursuant to the notice requirement. In the case of increases, Puget should not be obligated to serve increasing loads above 10 mw until after the end of the notice period.

For example, if a customer executed a contract for 40 mw of service, and dropped to 15 mw, this would be a change of 25 mw. The customer would be required to give three years notice, or else pay the demand charge for 15 mw (40 mw could be reduced to 30 mw without notice; the difference between 30 mw minimum permitted load without advance notice, and the 15 mw actual load would be subject to the fee) for the remainder of the three-year advance notice period. This would give Puget at least partial compensation for the costs of having the power supply available, and help make up the difference between the retail revenue it expected to receive, and whatever short-term revenues it can obtain by selling the power on the open market. Similarly, a growing customer wanting 25 mw of service could receive up to 10 MW of service prior to the end of the notice period, but would have no right to firm power above 10 mw until the end of the 3-year notice period.

Q. How does this compare with the treatment other regional utilities apply to large new loads?

A. BPA and many of the public utilities require new customers over 10 MW to pay a "large new single load" rate based on the BPA New Resources rate. Others required specific long-term contract terms. I believe the proposed notice requirement is reasonable, and will protect Puget against sudden requests for large amounts of service.

C. Lighting.

Q. Do you have any concerns about Puget's proposed lighting schedules?

A. Yes. There is no rate for high pressure sodium lighting under 70 watts. This type of very efficient outdoor lighting units also comes in 35 and 50 watt sizes. The structure of the Company's lighting tariffs encourages potential lighting customers to install larger units than they may actually need, leading to unnecessary energy consumption. Rates should be established at cost-based levels for smaller lamps.

XI. SPECIFIC ACTION ITEMS REQUESTED OF COMMISSION

Q. What specific decisions on Cost of Service should the Commission make in this proceeding?

A. First, I would urge the Commission to reaffirm its past support of the Peak Credit methodology for classification of production and transmission plant. Puget's proposed treatment of non-generation related transmission plant should be rejected again.

Second, the Commission should approve Puget's use of a combination of purchased capacity and combustion turbine costs for determining the "peak" component of the Peak Credit equation.

Third, the Commission should approve Puget's 200 hour definition for the "peak" period as being reasonably consistent with the Company's actual planning criteria for the use of peaking resources.

Fourth, the Commission should consider applying the same treatment for distribution lines, meters, and service for electric utilities as it has previously ordered for gas utilities, specifically that the costs be allocated on a combination of demand and energy criteria for distribution lines, and a combination of demand, energy, and customer indices for services and meters.

Finally, the Commission should direct Puget to file a revised cost of service study in the rebuttal phase of Cause UE-921262 which is consistent with the Commission's decisions on cost of service in this case, so that the Commission can use that study in making its rate spread decision in the general rate proceeding.

Q. What non-cost of service issues which relate to rate spread should the Commission resolve in this proceeding?

A. The Commission should reaffirm that issues other than cost-of-service will be considered in making rate spread decisions, as it has done consistently since Cause U-78-05. Specifically, I recommend that the Commission recognize the differential risk of certain customer classes, and perhaps more important, the higher risk of production investment and purchased power expense relative to distribution investment and customer accounts expense. The Commission should also consider differential growth rates of different customer classes in its decision.

Q. How should the Commission apply these differential risk and growth rate consideration in the spread of rates?

A. I recommend that the Secondary General Service class, which is the fastest growing class on Puget's system, receive at least the same increase as the residential class, regardless of the results of the average embedded cost of service study. I further recommend that the Commission incorporate the differential risk component by setting a target parity revenue to revenue requirement ratio of .95 for the residential and lighting classes, and a target parity ratio of 1.05 for the secondary, primary, and high voltage general service classes and the resale class. I have proposed that no class receive less than 50% of the average increase per kwh, nor more than 150% of the average increase in an effort to gradually move all classes toward the target parity ratios I have proposed.

Q. Turning to rate design, please list the specific decisions you think the Commission should make with respect to residential rates?

A. First, the Commission should approve a residential customer charge increase no greater than the average increase applied to the residential class, and in no case higher than $5.00/month.

Second, the Commission should approve a two-block residential rate, with 600 kwh included in the first block.

Third, the Commission should apply any rate increase to the residential class by first moving the end-block toward the level proposed by the Company. If that change in the tailblock charge does not produce the amount of revenue required from this class, only then should the $.04096/kwh initial block rate proposed by Puget in Cause UE-920499 be increased. The $.04/kwh initial block rate proposed in Cause UE-920499 is a true hydro-based rate consistent with baseline rate principles, and it should be preserved if possible.

Q. What specific decisions should the Commission make with respect to Secondary General Service rates?

A. The Commission should approve separating the current Schedule 24 into two separate schedules, Schedule 24 for non-demand metered customers, and Schedule 25 for demand-metered customers. The proposed Schedule 26 for large secondary customers should be rejected.

The existing Schedule 29, for secondary voltage irrigation, should be eliminated, and the customers served on Schedule 25.
The proposed rates for Schedule 24 do not achieve the same 20% seasonal differential proposed for other general service rates, simply because the seasonal demand charge is not applied to the non-demand-metered customers. The energy charge should therefore be modified to include a 20% seasonal differential.

The proposed declining block rate for Schedule 25 is unnecessary and does not achieve the stated purpose. The proposed demand charge should be subject to an energy constraint of \$.02 - \$.04/kwh to protect the low load factor customers.

Q. What about the Primary General Service rates?

A. Schedule 43 should be frozen, and the all-electric requirement in this rate should be dropped. The Schedule 35 primary irrigation rate should be eliminated, and the customers served on generally available rate schedules. The other changes proposed by the Company should be approved.

Q. What decisions should be made on the High Voltage rates?

A. The only exception I take to the Company's proposed High Voltage rates is the level of rates, which is insufficient.

Q. How should the Commission address the proposed interruptible rates?

A. The Commission should approve all of the interruptible rate options, including the residential water heat schedule. The Company should be directed to implement a residential water heat interruptibility program as part of its new customer connection policies, and to make that option available to existing water heat and electric hot tub customers in areas served by load control systems.

Q. What changes to the line extension / hook-up fees should the Commission approve?

A. The Commission should approve my proposed $200/kw hook up fee for residential space and water heating connections. This will more fairly recover the costs of serving growing loads from the customers causing the growth, and will encourage builders to install natural gas space and water heating in areas where a builder contribution is needed to secure gas service under the gas utility line extension policies without burdening existing gas customers.

Q. What notice should the Commission require for changes in load by large customers?

A. The Commission should limit Schedules 46, 48, and 49 to customers executing long-term contracts with the Company which provide for a minimum 3 year notice for changes in load over 10,000 kw or 10 average megawatts, a 5 year notice for changes over 30,000 kw, or 30 mwa, and a 7 year notice for changes in load over 50,000 kw or 50 average megawatts.

XII. SUMMARY

Q. Please summarize the impact of your recommendations?

A. My recommendations will more fairly apportion the costs of Puget's production, transmission, and distribution system among all customer classes. They will encourage cost-effective energy conservation, and discourage uneconomic energy consumption among all types of customers. They will create new rate options which will allow customers the ability to reduce their energy bills by taking steps to reduce Puget's energy costs. And finally, they will ensure that growth on Puget's system more fully covers the costs and risks which that growth imposes on the system.

Q. Does this conclude your prepared testimony?

A. Yes.