Christine O. Gregoire
ATTORNEY GENERAL OF WASHINGTON
Utilities and Transportation Division
1400 S Evergreen Park Drive SW • PO Box 40128 • Olympia WA 98504-0128 • (206) 753-2281

July 9, 1993

Mr. Paul Curl, Secretary
Washington Utilities and
Transportation Commission
1300 S. Evergreen Park Dr. SW
P. O. Box 47250
Olympia, Washington 98504-7250

Re: WUTC v. Puget Sound Power & Light Co.
Docket No. UE-920499

Enclosed for filing in the above docket are the original and nineteen copies of Brief on Behalf of Staff of Commission re: Cost of Service, Rate Spread and Rate Design. Copies have been sent to all parties.

Very truly yours,

DONALD T. TROTTER
Assistant Attorney General

DTT:nh
Enc.
cc: All Parties

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND POWER & LIGHT CO. Respondent.	)	DOCKET NO. UE-920499

BRIEF ON BEHALF OF STAFF OF COMMISSION
RE: COST OF SERVICE, RATE SPREAD
AND RATE DESIGN

CHRISTINE O. GREGOIRE
Attorney General

DONALD T. TROTTER
Assistant Attorney General
Counsel for Washington Utilities
and Transportation Commission

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I. INTRODUCTION

This docket was initiated in response to the Commission's order in Dockets UE-901183-T and UE-901184-P (the "Decoupling Case") in which Puget Sound Power & Light Company ("Puget" or "Company") was directed to file a case raising cost of service (COS), rate spread, and rate design issues by April, 1992. (Third Supp. Order in Decoupling case at 24). This filing responds to that directive, and a host of cost of service, rate spread and rate design issues are presented. In addition to analyzing the issues, we also provide a table summary of staff recommendations in Part VII of this brief.

Despite the fact that many of the issues in this docket are policy-related, it must be remembered that the burden of proof remains on the Company to demonstrate its cost of service, rate spread, and rate design proposals are fair, just and reasonable.

In its order in WUTC v. Washington Water Power Co., Cause No. U-82-10 and U-82-11, (1982) at 36-37, the Commission enunciated three policies:

1. Forward looking embedded cost studies should be used;

2. The "peak credit" method should be used to classify energy and demand costs for production plan, using multiple peaks for better representation of peak; and

3. Transmission costs should be classified using the peak credit factors.

The Staff case has followed and implemented these policies. Additional policies that "drove" Staff's analysis were:

1. The cost of service study should recognize the Commission's resource planning initiatives;

2. Price signals to customers should reflect the need for energy conservation, seasonality and the impact of growth management; and

3. Rate design and rate spread proposals should balance economic and equity issues, such as rate parity and gradualism.

(Sorrells, Ex. T-33 at 2). The Staff case fulfills these policies.

The Staff has examined the Company's cost of service study in detail and, in general, finds it acceptable. The major Staff/Company difference lies in the classification of non-generation-related transmission costs. There has been an insufficient showing by Puget and certain other parties to justify abandonment of longstanding Commission policy on this issue. Staff's proposal to maintain consistency in classifying these costs to demand and energy is well-supported by the record, and should be accepted.

On rate spread issues, Staff also agrees with Puget's proposal to move one-third toward parity, although the rate impact of PRAM 3 and the current rate case justifies Commission reevaluation of this issue when it considers its decision. The policy direction - meaningful movement towards parity - is important, however, and should be implemented.

Rate design issues are numerous, affecting almost every schedule. It is difficult to generalize on these issues, although the trend to provide more customers with a marginal cost price signal is an improvement.

In this brief we address the numerous issues presented. For reasons stated below, the Commission should adopt the recommendations of the Staff in this case.

II. PRELIMINARY ISSUES

Before proceeding to a discussion of major issues, it is important to address a preliminary matter, whether the rate design proposed is justified by the existence of decoupling?

A. The Proposals At Issue Are Not Justified By the Existence of Decoupling; Cost of Service Principles and Rate Design Proposals Are Justified Even if Puget Were Not Decoupled.

While Puget initially suggested that many of its proposals were justified by decoupling, a close examination of the record shows that this position cannot be sustained. For example, Mr. Knutsen stated that decoupling caused Puget to initiate rate designs that "may now be appropriate" (Ex. T-1 at 3), but then went on to note that the Company's proposals are consistent with its IRP, reflect accurate price signals, and are consistent with policies on rate design (acceptability, equity, fairness, stability, etc.) (Id. at 4-5). Obviously, these policies are not unique to a decoupled environment.

Ex. 1 to Mr. Hoff's deposition (Ex. 31), identified Puget's view of an appropriate rate design absent decoupling. But this exhibit identifies proposals that Puget has never been granted (e.g. minimum system, elimination of seasonality) (Hoff, Tr. 14). It is simply bootstrapping to suggest these proposals are necessary "absent decoupling," when they have never been accepted under any prior regulatory scheme.

Other Company rationales supporting "decoupling-related rate design" stem simply from the fact of collaboration, which was <u>initiated</u> by decoupling, not justified by it. (Hoff, Ex. 31 at 19-20). For example, Mr. Hoff could not say why moving from 12 to 200 hours for measuring peak was "dictated" by decoupling. (<u>Id.</u> at 20). In addition, concerns about "moving toward parity" and "revenue instability" must be viewed in light of the large rate increases in recent times. These increases have <u>heightened</u>, not <u>reduced</u> concern for rate shock or impact on Company revenues. While earnings have been stabilized, rates have increased significantly.

Finally, it is noteworthy that when the Company initiated its rate case last October, it did not even include decoupling, yet no changes to the rate design docket were made. Although the Company "hoped" decoupling would return in some form (Hoff, Ex. 31 at 11), it had no assurance it would or in what form. This is at least some evidence that decoupling and the proposals at issue here, are not directly related.

It is Staff's view that the rate design/COS issues in this case are not dictated by the presence or absence of decoupling. The issues presented for resolution can be resolved on their relative merits; decoupling should not be an issue either way.

III. COST OF SERVICE ISSUES

The purpose of a COS study is to functionalize, classify, and then allocate the cost of serving customers. (Lynch, Tr. 60). At that point, rate spread analysis takes place to determine the movement toward cost responsibility established by the cost study.

A. Functionalization of Costs.

No issues arose on the functionalization of costs to production, transmission, distribution, customer and general.

B. Classification of Costs - Issues

The cost classification issues arise primarily in the classification of the functionalized costs to demand, energy and customer categories. We outline the issues below, and then address each in order:

Production Costs

> Should a peak credit method be used or should a uniform % increase be implemented?
>
> If a peak credit method is used, how should the peak credit method classify costs to demand and energy?

Transmission Costs

> Should non-generation-related transmission costs be classified to demand or to demand and energy?

Distribution and Customer Service and Billing Costs

> Should distribution costs be classified pursuant to a "minimum system" analysis, or should the basic charge continue to be

comprised of services, meters, meter reading and billing services?

Conservation Costs

Should conservation costs be classified to each class based on savings, or as a resource for all Puget's customers?

Seasonality

Should costs be seasonally differentiated?

We analyze these and other relevant issues below.

ANALYSIS

C. Classification of Production Costs.

Puget proposed the use of a "peak credit" method to classify production plant demand and energy. (Lynch, Ex. 3, p.2). As the summary in Ex. 77, p. 1 shows, all parties except the FEA support the method. We demonstrate below that FEA's opposition to the peak credit method is unsupported.

The following Table summarizes the specific peak credit factors sponsored by each party:

PARTIES' POSITIONS ON THE PEAK CREDIT METHOD

Party	Demand/Energy Factors
Staff	Between 12/88 and 16/84 (when gas alone is used on peak, the factor is 12/88)
Puget Power	16/84
Public Counsel	13/87
WICFUR	31/69
SWAP	30/70
BOMA	16/84
FEA	Does not support Peak Credit Method

1. <u>The Peak Credit Method is An Appropriate, Recognized Methodology for Classifying Production Costs Between Demand and Energy</u>.

As indicated above, the only party to oppose the peak credit method <u>in principle</u> was the FEA.[1] Mr. Knobloch testified that the peak credit method was "not well recognized" and proposed a uniform percentage allocation in the absence of a valid study. (Ex. T-40, p. 2, 4). He claimed the peak credit method was not discussed in the NARUC Cost Allocation Manual. (Ex. 42).

However, the peak credit method in fact <u>is</u> reflected in the NARUC Cost Allocation Manual. It is called the "equivalent peaker method" in that manual. (Sorrells, Tr. 1507; Lazar, Tr. 1631-32). The equivalent peaker method is also referenced as a method used by various Commissions in the 1989 EES survey. (Ex. 55 at B-2).

But even if Mr. Knobloch were not in error regarding the NARUC Cost Allocation Manual, there is strong support for the use of the peak credit method.[2]

The peak credit method is able to reflect the fact that in a hydro-based system, Puget has the option of selecting baseload or peaking resources to meet its needs. Therefore, it is appropriate to classify part of production plant to demand and part to energy.

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[1] Some witnesses opposed the particular calculation of the peak credit method as well. Those issues are discussed in the following section.

[2] Mr. Knobloch's criticism at Tr. 1579 and 1596-99 that Puget's peak credit method doesn't meet the Manual's definition is also without merit. Because Puget uses peaking facilities for various non-peak purposes, separation of costs is necessary. Nothing in the Manual precludes this, which in fact is a key factor supporting the use of the peak credit method in the first place.

(Lazar Ex. T-43 at 7; Sorrells, Tr. 1561) (Mr. Schoenbeck testified similarly. (Ex. T-73 at 31, Tr. 1796).

The Commission in its order in the 1982 rate case involving Washington Water Power adopted the peak credit method for the same reason; the peak credit method better reflects the energy requirements of a hydro-based system. (Order in Cause No. U-82-10 and U-82-11 at 37, cited by Sorrells, Ex. T-33 at 6). It has been approved in orders involving Puget (Cause No. U-82-38) and Pacific Power & Light (Cause No. U 82-12) as well. (Tr. 1571-73). Staff and most other parties supported its use in this case.

In addition, it is pertinent to note that the peak credit method was endorsed by the Collaborative Group (Concept No. 6, Ex. 11 at 19). It allows forward-looking capacity and energy relationships to be reflected in the classification of embedded plant. The results are similar to those produced by other standard methods. Id.

Inasmuch as there is no credible evidence indicating that the peak credit method should not be used, and ample evidence to support its continuance, we urge the Commission to again articulate its support of that method in principle.

2. Puget's Assumptions Regarding Peaking Facilities Should be Adopted, Except for Choice of Fuel for the Combustion Turbines.

Application of the peak credit method by Puget generated a demand/energy split of 16%/84%, a slight change from its initial proposal of 17%/83%. (Lynch, Tr. 61, Ex. 5 at 2, Ex. 564 at 3). The calculation was performed by dividing the cost of a combined cycle combustion turbine (CCCT) into one-half the levelized cost of a peaking combustion turbine (CT). (Ex. 5, p. 2, Ex. 564 at 3)(Lynch, Tr. 64, 107, Hoff, Ex. T-8 at 11-12, Tr. 328-29).

Puget's approach was generally accepted by Public Counsel and Staff, but was opposed by WICFUR and SWAP. There are three issues involved: (1) choice of fuel; (2) use of one-half of a CT, and (3) use of an 80% capacity factor for the CCCT. We address these issues below.

a. <u>The Fuel for the Peaking Plant Should Be Based on Test Year Use of Gas</u>.

The use of fuel for operating the CTs for 200 hours was analyzed by several witnesses. Puget uses both oil and gas for a peaking fuel. (Lynch, Tr. 65-66, 109-09), but assumes it will use only oil (the more expensive fuel) for purposes of the cost study, on the basis that the CTs <u>may</u> be interrupted. (Lynch, Tr. 108, Ex. 17 at 32-34, Hoff, Tr. 208).

But as Staff testified, in the test year only gas was used. (Sorrells, Ex. T-33 at 11). Puget admitted that only in an <u>extreme</u> case would gas be interrupted for all 200 hours of use. (Lynch, Tr. 1841-42, Ex. T-76 at 6). As Staff showed in Ex. 37, if gas is the fuel used, a 12%/88% demand energy split results. Public Counsel assumed 50 hours would be gas, for a 13%/87% split. (Ex. 45 at 6).

The issue here reflects some tension between the "forward looking" nature of this embedded cost study and the tying of the cost study to the test year cost of service. It is Staff's position that when this tension occurs, it is appropriate to accept the result that more closely ties to the actual costs incurred. Staff's analysis more accurately reflects actual use of fuels in the test year. In future studies, it may be appropriate to use a mix of oil and gas that is representative of test year conditions. (Sorrells, Ex. T-33 at 11-12).

b. <u>The Use of One-Half of a Combustion Turbine is Proper Since it Reflects the Hydro-Firming Capabilities of the CT</u>.

As discussed previously, the peak credit method has a major advantage in that it permits separation of facilities to different uses. (Lynch, Ex. T-76 at 6). Puget's CTs provide a hydro-firming function in addition to peaking functions. (<u>Id.</u> at 5-6) (Lazar, Ex. T-43 at 10). This is consistent with the Company's planning criteria. (Lazar, Tr. 1635). WICFUR's suggested 100% use of the CT's levelized costs should be rejected for this reason. (Schoenbeck, Ex. T-73 at 6).

This is not to say that the use of 50% of the CT's levelized cost is the epitome of precision. (<u>See</u> Schoenbeck, Tr. 1800-01). Puget admitted it was a "judgment call" (Hoff, Tr. 196), but the calculation was verified by a cross-check against the value of a capacity contract. (Lynch, Ex. 17 at 45-46, Hoff, Ex. T-8 at 12). This is perhaps the most judgmental aspect of the COS study presented. We believe Puget's measurement is within a range of reasonableness, assuming that the resulting parity ratios are not viewed with exactness, either.

c. An 80% Capacity Factor for the CCCT is Appropriate.

WICFUR also challenged the assumption that the CCCT would have an 80% capacity factor. (Schoenbeck, Ex. T-73 at 6). WICFUR proposes that a system load factor be used. (Id. at 8). But the 80% factor is consistent with the Company's 1993 avoided cost filing. (Lynch, Ex. T-76 at 7) It is appropriate to reflect that choice of resource options here.

There was some discussion whether Puget's COS study was consistent with its avoided cost filing in other respects. (Schoenbeck, Ex. T-73 at 10-11). However, as Ms. Lynch pointed out, the ratio for demand in the avoided cost filing's analysis of the CT and CCCT showed a ratio of 19%, within a reasonable proximity to the 16% used by Puget. (Lynch, Tr. 1847).

D. Classification of Transmission Costs.

Puget classified transmission costs using two methods. Non-generation related transmission was classified 100% to demand. Generation related transmission was classified according to the peak credit method. (Lynch, Ex. 3, p. 2).

The only issue appears to be related to non-generation related plant, which we address below.

1. Non-Generation Related Transmission Should be Classified to Demand and Energy Using the Demand/Energy Split.

Non-generation related transmission is that transmission plant that is not used to connect remote generating facilities to the network. (Lynch, Ex. T-1 at 17). In other words, it is the transmission network other than "backbone" transmission. (Lynch, Tr. 145-46). Puget has $253.5 million in transmission plant that is non-generation related. (Sorrells, Ex. T-33 at 8).

The Company classifies this plant entirely to demand. (Id. and Lynch, Ex. 3, p. 2, Tr. 69, 114). The rationale presented is that this plant is primarily designed to meet the peak load on the system. (Lynch, Tr. 71, Ex. T-2 at 17: Ex. T-76 at 8-9). SWAP, WICFUR and BOMA support this classification. (See Ex. T-76 at 8). Staff and Public Counsel oppose it. On rebuttal, Ms. Lynch noted that the NARUC Cost Allocation Manual states that a forward-looking marginal cost study assumes transmission investment is driven by incremental peak load. (Ex. T-76 at 9). (Emphasis supplied).

None of the Company's rationales pass muster. First, Ms. Lynch's reliance on the NARUC Cost Allocation Manual is misplaced since we are not using a forward-looking marginal cost study, but a forward-looking embedded cost study. (Lynch, Tr. 1840). The NARUC Manual supports allocation of transmission costs to demand and energy in an embedded cost study. (Ex. 39, p. 1, last ¶ and p. 6-7). Many assumptions would be different using a marginal cost study, a subject not addressed by Puget.

Second, transmission costs are not solely a function of capacity, and therefore should not be allocated solely to demand. It was undisputed that the average cost per kwh is lower the higher the capacity of the line. (Sorrells, Ex. T-33 at 9; Lazar, Ex. T-40 at 12). The Company's IRP states that the cost of building transmission to meet peak loads is cheaper than building simply to meet off-peak loads, and that transmission is built to "meet energy needs." (Id. p. 3) (Ex. 39, p. 3-5) (See also, Lynch, Ex. 17, p. 41-42). Thus, a 100% allocation to demand is unjustified.

Third, if non-generation related transmission is allocated all to demand, this means certain customers which are served by this plant do not pay for it, if they do not use energy at peak. (Sorrells, Ex. T-33 at 9; Lazar, Ex. T-43 at 12, lines 14-22). (See also, Lynch, Tr. 124-25). Staff's proposal eliminates this unfairness.

Finally, the Commission has a long track record of consistently rejecting, on the merits, the classification of non-generation-related transmission to demand only. It was rejected in the following dockets (Lynch, Tr. 114-117):

U-81-41
U-82-10
U-82-12
U-82-38
U-86-100
U-89-238-T
UG-901459

The foregoing is not meant to suggest that none of this plant can ever be determined to be demand related. Mr. Lazar testified that it would be possible to analyze the transmission grid, segment by segment, to determine what segments were sized only to meet demand and which were also sized to meet additional energy needs. (Ex. T-43 at 15-16). Suffice it to say the analysis has not been done. Until a credible study has been done, the Staff's proposal to classify non-generation-related transmission as both demand and energy related is appropriate and consistent with well established Commission policy.

E. Classification of Distribution Costs.

Puget classified to customers those distribution costs related to metering (meters, meter reading and billing) and the customer's service drop. Remaining distribution costs (poles, transformers, conducts, etc.) were classified to demand. (Lynch, Ex. 3, p. 2).

The sole issue here relates to whether more distribution costs should be classified to customers than metering costs and the service drop. As we demonstrate below, the clear answer is "No."

1. Distribution Cost of the Service Drop, Meters, Meter Reading and Billing Services Should be Classified as Customer Related; the "Minimum System" Approach Should Again be Rejected.

In its Third Supp. Order in Docket No. U-89-2638-T, the Commission admonished that "The parties should not use the minimum system approach in further studies." Like an unwelcome relative, and notwithstanding this clear policy directive, the issue has come back for a visit.

Puget based its case on a basic customer charge concept, in which metering costs and services are classified as customer related, but the balance of distribution costs (substations, poles, conductors, transformers and conduit) are classified to demand. Despite its promise that Puget in this case would not revisit its prior positions (Knutsen, Ex. 16, p. 13), the Company testified that conceptually it preferred the "minimum system" analysis in which a hypothetical system is created which attempts to determine what distribution plant would "be there" regardless of demand. (Lynch, Ex. T-2 at 19, Ex. T-76 at 2 and 29-31); BOMA and WICFUR agree. (Saleba, Ex. T-54 at 12-16; Schoenbeck, Ex. T-73 at 28-30).

It goes without saying that the Commission has never accepted the "minimum system" analysis. It is noteworthy that none of the Commission's concerns in the last case (double allocation of costs; overallocation to low use customers) have been directly addressed by any party supporting the minimum system method.

It should also be recognized that the "minimum system" does not in fact exist. (Sorrells, Tr. 1560). It is a theoretical construct that may or may not have any relationship to what is actually installed in the field.

The FEA raised a hypothetical through various witnesses regarding a situation with one commercial customer and one hundred residential customers, suggesting that classifying poles, conductors and transformers to demand would be unfair. (See e.g., Saleba, cross-examination of Tr. 1718-20, Lazar, Tr. 1662). But the hypothetical ignores the fact that these customer groups have different load factors. (Lazar, Tr. 1663). No conclusions can be drawn from this hypothetical, even apart from the fact that hypothetical was not tied to any of Puget's territory.

Other issues have been raised but left unanswered. For example, WICFUR's witness testified that customer density affects customer costs, (Schoenbeck, Ex. T-73 at 30), but he places the burden on others to prove that density varies between customer classes. (Id.)

We submit the burden lies with those proposing the minimum system approach to demonstrate that there is no density issue, or it has been dealt with appropriately. WICFUR's point that we should be "approximately right" (Id. at 31) presupposes the validity of the minimum system approach. Tripling the basic charge ($4.75 to $15) (Lynch, Tr. 73, 125-26) without more substantial support than this does the ratepayers an injustice.

Nor does the fact that the NARUC Cost Allocation Manual recognizes the minimum system constitute justification of its use. (See Saleba, Ex. T-54 at 13). Mr. Saleba recognized that the Manual has been subject to question by the WUTC on this point. (Tr. 1732-33, Ex. 57). The Manual raises the point that the minimum system should only include that part of the distribution system on the customer's property. (Saleba, Tr. 1731). No analysis other than conjecture was done to determine what this evaluation would show. (Id. Tr. 1732). Professor Bonbright has articulated well founded reasons for rejecting a minimum system approach. (Ex. 56).

BOMA used its evaluation of the minimum system approach to conclude that BOMA customers are cross-subsidizing others (Saleba, Ex. T-54, at 16). But this analysis presupposes the approach is valid. Absent proof of the validity of the minimum system approach, BOMA's conclusions lack foundation.

It is also pertinent to note that Puget's charges for line extensions for commercial customers are based on expected revenues, not the actual cost of the installation. (Lazar, Ex. T-43 at 18-19). This is a good indication that such plant is at least in part energy related, not customer related. (Id. Tr. 1638).

In sum, the Commission should maintain its basic customer charge policy.[3] This will have the collateral benefit of sending a stronger price signal to customers to use energy efficiently. (Sorrells, Ex. T-33 at 13). The proponents of the minimum system method have not addressed the concerns articulated in past Commission orders. The method has not been accepted before; it should not be accepted now.

F. Classification of Conservation Costs.

Puget initially classified conservation costs the same as production costs, using the peak credit method. (Lynch, Ex. T-2 at 20-21). Classification to the "benefitting" class was rejected since all classes benefit from conservation as a resource. (Id. at 21). On rebuttal, Puget changed its position, but not its result and looked to future analysis to qualify the effects of this change in approach. (Lynch, Ex. T-76 at 17). As we demonstrate below, Puget was right in the first instance.

1. Conservation Costs Should Be Treated as a Resource, Not as a Class-Specific Benefit.

WICFUR proposed adjustments to the allocation factors to reflect each customer classes' portion of conservation investment installed by Puget in calculation of the demand and energy allocation factors. (Schoenbeck, Ex. T-73 at 22-27). The basis

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[3] We recognize the "gas distribution model" generates a much lower basic customer charge. (Response to Bench Request 7). However, Mr. Lazar, who proposed this analysis, indicated that it was mostly meant to provide "the other side" of the position advanced by minimum system advocates, to show that the basic customer method is a reasonable one. (Tr. 1624). We do not recommend use of the natural gas model for that reason.

for this proposal is the assumption that those customers who do not participate in the programs are "losers" and those who do are "winners." (Id. at 24-25).

Staff disagrees with WICFUR's analysis.

Conservation serves the purpose of reducing the need for additional supply-side resources. The cost of the conservation obtained by Puget is below the avoided cost of the next supply-side resource that Puget would otherwise purchase. Therefore, conservation can mitigate the increase in costs of electricity services. This benefits all Puget's customers by delaying the need for additional, more expensive, supply-side resources.

Staff recognizes that direct benefits accrue to the conservation program participants along with the indirect benefits that accrue to all customers, as stated above. Staff does not agree with the position of WICFUR that the conservation benefits only specific classes. The reduction in the need for additional supply-side resources benefits all classes because all classes share in the lower avoided cost. Conservation is a valuable resource that reduces total load. (Lynch, Tr. 68-69, 95). Therefore, conservation should continue to be seen as a resource for all classes no matter which customers or classes receive the direct benefit of the conservation measures. (Sorrells, Tr. 1525-26).

G. Allocation Factors.

The allocation of customer and energy costs in the COS study is relatively straightforward; customer costs are generally allocated based on the number of customers in each class. Energy costs are allocated based on test-year kwh. (Lynch, Ex. T-2 at 29-30). On rebuttal, the Company proposed to temperature adjust the allocation factors to be consistent with the weather-adjusted loads in the COS study, although data was available only to adjust the energy factor attributable to the residential class. (Lynch, Ex. T-76 at 18-19, Tr. 1826). This adjustment is reasonable and should be accepted.

The demand cost allocation presented more complicated issues. The first issue relates to Puget's use of 200 hours as the basis for its demand cost allocators. (Lynch, Ex. T-2 at 27). The second issue relates to SWAP's proposal to differentiate the energy allocation factors by season. (Carter, Ex. T-58 at 3).

As we demonstrate below, the 200 hour assumption is an appropriate, if understated level of hours on peak. Second, the energy allocation factors should not be differentiated by season, since the cost study does not measure cost of service by class by season.

1. <u>A Minimum of 200 Hours Should be Used to Measure Peak</u>.

Puget used the top 200 hours as the number of peak hours used in its calculation of the demand allocation factors. (Lynch, Ex. T-2 at 27). This was a change from the 12 hours used in previous studies. (Tr. 87). No party other than WICFUR contested the use of the 200 hours. WICFUR's proposal should be rejected.

The 200 hour proposal is based on the fact that it more accurately reflects Puget's planning criteria. (Lynch, Ex. T-2 at

27); it reflects the hours Puget's peaking units are planned for use. (Lynch, Tr. 99, 151). Puget keeps 200 hours of fuel stored at the sites of its peaking units. (Lazar, Ex. T-43 at 8).

WICFUR proposes only a few hours be used, based on its view that the peak credit classification method does not distinguish between the various resources or the hours they will operate. (Ex. T-73 at 9-10). The problem with a very small number of peak hours, however, is that such a peak can be met by interruptibility or short-term power purchases, rather than CTs. (Lazar, Ex. T-43 at 9).

The purpose of the 200 hours is to be more representative of system peak and the resources put in place to serve that peak. The Commission has expressed a policy preference for multiple peaks. (See supra at 2). Other parties recommended peak be measured using up to 1500 hours, since Puget has obtained exemptions to operate its CTs at that level. (Lazar, Ex. T-43 at 9). The 200 hours is not excessive, and should be adopted.

2. Seasonally Differentiated Energy Allocation Factors Should Not Be Used Since Underlying Costs are Not Differentiated

As Ms. Lynch explained in Ex. T-76 at 19, the cost of service study is not designed to present seasonally differentiated results or to determine the cost of service by season by class. Therefore, using an energy allocation factor to reflect what the underlying cost study does not measure would be inappropriate. SWAP's proposal should be rejected.

H. Miscellaneous Issues.

1. Differential Risk Between Customer Classes.

The issue of differential risk between customer classes was an issue raised by Public Counsel. Mr. Lazar provided analysis tending to demonstrate that each customer class poses different risks to the company; that rapid growth in the commercial class imposes higher costs on the system; and that production plant has a higher risk than other plant. (Ex. T-43 at 22-29).

Mr. Lazar concludes that the commercial and industrial classes impose relatively more risk on Puget's system, and the COS study currently does not reflect that risk. (Id.) The company responded by arguing that the risks identified are not quantified and do not necessarily relate to specific customer classes, but rather specific customers. Puget suggests alternative analyses that could be conducted in future cases to address these issues on a customer-specific basis. (Hoff, Ex. T-83 at 20).

There appears to be no dispute that the commercial class is the fastest growing class of customer on Puget's system. Likewise, there is no question that industrial customers do impose a unique risk, at least short-term, to the extent they can and do leave the system or impose large power requirements. However, quantification of these relative risks is problematic, and Mr. lazar provides only general observations in this regard.

We submit Puget should be required in future cases to analyze this issue and propose appropriate customer and customer class-specific measures that address these issues. In the meantime, Public Counsel's analysis should be used in a qualitative way in recognition that the COS study is not "perfect". The residential class should be given the "benefit of the doubt" by the Commission when it must choose between policy options that might impact the residential class more severely than other classes.

2. Firm Resale.

During the hearings, the Bench raised questions concerning Puget's firm resale class (e.g. Tr. 1674-1678 and 1898-1902). Staff found the parity ratio for this class to be only 74%. Other parties also found this parity ratio to be about this low. Since the amount of revenue requirement collected from this class needs to be increased, Staff has addressed this issue in the general rate case (Docket UE-921262). Staff therefore recommends that this issue be synchronized with the general rate case and dealt with in that forum. The general rate case will allow an opportunity for parties to establish the appropriate level of revenue requirement for the firm resale class.

IV. RESULTS OF THE COST OF SERVICE STUDY

The various parity ratios resulting from the cost study analyses of the parties were summarized in Exhibit 78. That Exhibit is reproduced below, but is updated with Staff's Ex. 81 analysis:

PARITY RATIOS

Party	Residential Total	Secondary <50kW	Secondary 50<kW<=350	Secondary >350 kW	Primary Total	High Voltage Total	Lighting Total	Firm Resale Total
Staff	98%	108%	115%	112%	91%	84%	133%	74%
Puget Power	96%	111%	118%	115%	93%	88%	136%	77%
Public Counsel	>100%	<110%	<110%	<110%	<90%	<83%	>131%	<70%
WICFUR	87%	123%	130%	130%	108%	105%	144%	92%
WICFUR	84%	122%	146%	145%	118%	105%	146%	99%
SWAP	95%	110%	117%	117%	95%	92%	137%	79%
BOMA	93%	109%	130%	127%	100%	86%	136%	80%

V. RATE SPREAD ISSUES

Rate spread issues include consideration of rate parity, gradualism, rate stability, equity and fairness. Rate parity and gradualism were recommendations of the Rate Design Task Force. (Ex. 10, p. 12-14). No witness disagreed with the proposition that rate parity (i.e., all classes of customers paying their cost of service) was a goal, although there was a difference in how fast Puget should move towards parity.

Puget proposes that rates move one-third toward parity; a position to which Staff and WICFUR agree. (Hoff, Ex. T-8 at 25, Ex. 18 at 5; Sorrells, Ex. T-33 at 15: Schoenbeck, Ex. T-73 at 34-35). The Company's one-third proposal is measured by calculating the dollar "subsidy" and dividing by three. (Hoff, Ex. T-8 at 25).

It is no surprise that certain customers who show an "over payment" of COS articulate a position of self-interest and demand rate parity now. BOMA, for example, sees no reason not to go to 100% parity at once. (Saleba, Ex. T-54 at 10, Tr. 1705-06).

While we understand BOMA's concern, we do not believe BOMA's self-interest is "enlightened" self-interest. Puget's customers have borne the brunt of large rate increases over the past two years, with a rate case and $76 million in PRAM 3 still to come. While BOMA may not believe a 25% rate increase is excessive (Saleba, Tr. 1722), we submit that a one-third movement toward parity is more measured response than the wrecking ball approach advocated by BOMA. The Commission may well wish to mitigate the impact even further once it determines what level of rates will be approved in the rate case and PRAM 3 proceedings.

VI. RATE DESIGN ISSUES

A rate structure is as vital to a utility as any business; it sets the price and manner of recovery of the commodity and has implications for the amount of commodity sold. On the record, there are several rate design proposals. We address them in general sequence by schedule.

A. Schedule 7 - Residential.

Schedule 7 currently has 3 rate blocks, a winter/summer differential of 5%, and a basic charge of $4.55. Puget proposed to change this schedule to 2 rate blocks, a winter/summer differential of 10%, and a basic charge of $5.00. (Hoff, Tr. 161, 171-72, Ex. 570, Schedule 7 and Ex. 569 at 3).

1. Moving From 3 to 2 Blocks is Appropriate; the Second Block Should Start at 400 kwh.

There was no objection to the proposal to move from 3 to 2 rate blocks in Schedule 7. According to Exhibit 10, p. 19 (the Task Force Report) the 3 tier structure is no longer appropriate since it fails to meet expected customer load profiles. According to the Report, the first block should reflect an allocation of hydro-resources; the second should reflect the marginal cost of resources. (Id.) As Mr. Lazar testified, a two block rate is simpler, it better matches usage, and the initial block can more accurately reflect the cost of hydro. (Ex. T-43 at 39).

There is an issue regarding at what level the second block should start. The Company initially proposed 500 kwh for the winter months. (Ex. 21). Upon filing the rate case, the Company changed this to 800 kwh, due to rate impact concerns. (Ex. 571, Ex. T-83 at 13).

However, there are other factors to consider. First, the rate impact may not be as large as the Company has requested. The Commission can consider this in its deliberations in this case. Second, the Company's 800 kwh proposal is too high; that level is more than the monthly usage for lights and appliance customers. Thus, the 800 kwh block will not produce a true marginal price signal. (Ex. 572 at 12, Lazar Ex. T-43 at 41).

Staff witness Sorrells recommended a gradual move toward 400 kwh to give more customers a marginal cost price signal. (Ex. T-33 at 17). Based on Staff's rate case revenue requirement, it is recommended that the move to 400 kwh is appropriate now. (Ex. 81 cover letter).

The Commission should balance the considerations of rate impact and price signal in designing Schedule 7. If Staff's rate recommendations are accepted, a move to a 400 kwh initial block is appropriate. Certainly no tail block over 600 kwh should be implemented, whatever the rate increase is to be.

2. <u>A Winter/Summer Differential of 10% is Appropriate for Schedule 7</u>.

Puget proposed an increase in the seasonal rate differential from 5% to 10%. (Hoff, Ex. T-8 at 12-13, Tr. 171). While this differential is an estimate, and a rough one at that (<u>See</u> Hoff, Ex. 24, Tr. 172, 232, Ex. 18, p. 42-49, 60), a larger differential than the current 5% appears to be appropriate.

3. A Basic Charge of $5.00 is Appropriate.

As we discussed in section IIID above, the classification of services, meters, meter reading and billing services on a customer basis is proper. That results in a $5.00 basic charge. (Ex. 569 at 3). That level is appropriate for Schedule 7.

B. Schedule 24, 25 and 26 - General Service, Small Demand General Service, and Large Demand General Service.

Puget proposes to split Schedule 24 into three schedules which more accurately reflect load characteristics. (Hoff, Ex. T-8 at 39, Tr. 167). (Ex. 570).

Staff did not dispute this split, which in Staff's view is a refinement worth making. (Sorrells, Ex. T-33 at 22).

The issues under this proposal relate to whether Schedule 25 should have an effective energy rate that declines for some customers. (Hoff, Ex. 18, p. 20-21) (Sorrells Ex. T-33 at 23). The Company indicated that this could not be solved without significant increases for some customers. (Hoff, Ex. T-83 at 14-15, Ex. 87). The Commission should require the Company to continue to analyze this issue and propose a solution in subsequent cases, including more detailed consideration of Public Counsel's recommended "energy constrained demand charge." (Lazar, Ex. T-43 at 48.) Puget's dismissal of this option on rebuttal as being administratively difficult (Hoff, Ex. T-83 at 15) does not mean it cannot or should not be done.

C. Schedule 29 - Secondary Irrigation and Drainage Pumping; Schedule 35 - Primary Irrigation and Drainage Pumping.

Puget proposes to maintain these two schedules, but moves the rates more in line with other commercial schedules. (Ex. 570, Sorrells, Ex. T-33 at 26). Both Staff and Public Counsel recommend elimination of these schedules on the basis that there is no reason to maintain them separate from other commercial customers, although some mechanism to handle the BPA discount would be required. (Sorrells, Ex. T-33 at 26-27; Lazar, Ex. T-43 at 50-51).

If the BPA should eliminate the credit, Schedules 29 and 35 should be eliminated. (Sorrells, Tr. 1550-51).

D. Schedules 31 and 49 - Primary and High Voltage General Service

The issues regarding Schedules 31 and 49 relate to whether seasonal differentiations in demand and energy charges should be reflected, and at what level, and SWAP's proposal to have a "summer peaking" rate schedule or other similar relief. We address these issues below.

1. The Seasonal Differentiation Proposed By Puget in Schedules 31 and 49 Is Appropriate.

Puget proposed rate changes to the Primary Voltage schedule by adding seasonally differentiated demand changes and increasing the seasonality of energy changes. WICFUR supported these efforts. (Schoenbeck, Ex. T-73 at 35).

Public Counsel testified the proposed rate design is reasonable and should be approved for Puget's Schedule 31, Primary General Service. (Lazar, Ex. T-43 at 51). However, Public Counsel notes that the overall level of rates is too low, as reflected in

Exhibits 47 and 48. Therefore, it has recommended in its cost of service and rate spread sections of its testimony that this class receive an increase per kwh which is 150 percent of the system average increase per kwh.

Staff did not contest the overall level of rates for Primary General Service. In Staff's cost of service study, as reflected in Ex. 81, Staff shows the Primary General Service parity ratio to be 92%. Although there is room to move this class toward parity, the current number is acceptable but improvements should be made in future rate cases.

FEA recommended that there be no change in cost recovery from demand and energy charges and the energy charges should remain the same. The Navy made this recommendation for all schedules with energy and demand charges. The basis for this recommendation is the Navy's belief that the cost of service study is flawed. (Knobloch, Ex. T-41 at 13). We demonstrated the flaws in the FEA's basis for proposal. Its recommendation should be rejected.

2. <u>A "Summer Peaking" Rate Schedule or Other Rate Designs to Accommodate Summer Peakers Have Not Been Justified, But Further Analysis May Justify Such Relief</u>.

SWAP presents a case supporting its request that SWAP customers either a) have a separate "summer peaking" rate schedule; b) be permitted to be served on the irrigation schedules or c) create a differential of $5.50 - $6.00/kw between winter and summer demand charges on Schedules 31 and 49. (Carter, Ex. T-58 at 8-13, Tr. 1774-75).

As the record shows, the second proposal is probably unavailable, since SWAP customers are not irrigators, and the irrigation schedules are designed to accommodate the BPA irrigator discount. (Tr. 1780-81).

Creating a separate schedule for SWAP customers is also problematic. "Food storage and food processing" businesses are not a unique class. (Hoff, Ex. T-83 at 8). Exhibit 69, which plots SWAP customer demand data, does not reveal a homogeneous characteristic: two of the six SWAP members shown (A and F) would not even be eligible for a new schedule. (Carter, Tr. 1756). Exhibits 70-72 show that SWAP customers are not so radically different from other Schedule 31 customers.

SWAP's recommended changes to the seasonalization of demand charges is also flawed. As we indicated earlier, the Company's 10% seasonality differential is a "rough approximation." SWAP took the absolute value of the difference between summer and winter marginal rate and applied that difference to the energy charges. (Carter, Ex. T-58 at 10-12). The problem with this approach is that Schedule 31 and 49 customers <u>are not charged</u> these marginal costs. Their rates are much lower. (Hoff, Ex. T-83 at 10). Until Schedule 31 and 49 customers actually <u>pay</u> marginal cost rates, the percent relationship is fair. (<u>Id.</u>)

Despite the foregoing, a summer peaking rate may have some merit. The record, however, is insufficient to reach a conclusion on what such a schedule would look like. The Company should be directed to conduct load analyses to determine the relative merits of such a schedule.

E. Schedules 36, 38 and 39 - Interruptible Rates

Puget proposed interruptible service credits for the secondary, primary and high voltage classes under Schedules 36, 38 and 39. Interruptions provide an alternative to peak generating resources, as stated in Puget's integrated resource plan (Hoff, Ex. T-8 at 50).

WICFUR stated that offering the interruptible tariffs on a limited and experimental basis is appropriate until experience is gained with these rate structures. WICFUR argued that the proposed interruptible reservation credit was too low because it is about 20 percent of the long-term fixed cost portion of providing firm capacity (Schoenbeck, Ex. T-73 at 36).

As Public Counsel stated that because the interruptibility is only available for a few hours, then it is not equal to the value of capacity which is available for much longer periods of time (Lazar, Tr. 1642-1644). Public Counsel also pointed out that if customers are not attracted at the rate set by Puget, then the credit could only be increased if the value made it cost-beneficial to do so. (Lazar, T.-43 at 54-55). Staff agrees with Puget's proposal for the reasons stated by Public Counsel.

F. Schedule 43 - Total Electric Schools.

This schedule is for all-electric schools. Puget proposes to "freeze" it, denying any new customers after October 1, 1993, as stated below in Exhibit 88.

Staff proposed the schedule should be frozen, on conditions:

1. New customers should be added only if they receive an approved Construction Report from the Energy Office by October 1, 1994.

2. Current customers must do Schedule 83 cost-effective conservation measures by September 30, 1996 to remain on the schedule.

3. Customers who switch part of their load to other fuels should move to Schedule 31.

(Sorrells, Ex. T-33 at 30).

There is no question that customers on this schedule are paying rates well below cost, and the "threat" of interruption is minimal, since it may occur only when they have very little load. There is no economic justification for this schedule. (Sorrells, Ex. T-33 at 28; Lazar, Ex. T-43 at 15-16). The Company's proposal in Exhibit 88 is substantially consistent with Staff's recommendation and should be accepted.

G. Schedules 30 and 48 - Experimental Schedules for General Service Customers.

Puget proposed two new experimental tariffs under Schedules 30 and 48 to provide a marginal cost rate with the energy and demand blocks customized for each customer (Ex. 8, p. 16-18 and Schedules 30 and 48 in Ex. 570). The purpose of these tariffs is to provide a price signal to each customer based on its consumption and demand. WICFUR agrees with Puget's proposal on optional rates. (Ex. T-73 at 35).

Public Counsel and Staff support the concept of these schedules but are concerned that Puget's proposal that these rates be voluntary will distort the purpose of establishing the rates. If the rates are not mandatory, then only customers planning to reduce their electric load will sign up for these schedules (Sorrells Ex. T-33, at 31 and Lazar Ex. T-43 at 55). Although Mr. Hoff believed that "expected consumption" may not materialize (Ex. T-83 at 11), we are not dealing with unsophisticated customers here. The value of the load research data gained under such an experiment will not be significant if only such customers have an incentive to sign up. There was no agreement on whether to make the schedules mandatory to new customers or having a mandatory rate, with the initial block set at 75% of the actual metered usage for the same period three years earlier (Ex. T-33, at 32 and Ex. T-43 at 56). Staff recommends the Commission reject these schedules and require additional analysis by the Company as to how such schedules could be successfully and meaningfully implemented.

H. Schedule 80 - Power Factor Adjustment

Reactive power is the portion of power supplied to a customer that does no work. (Sorrells, Ex. T-33 at 33). Customers with poor power factors require more power be provided. Whether a customer has a poor power factor is measured by the demand meter in units of kilovolt-amperes or kva. (Hoff, Ex. T-8 at 59).

1. The Power Factor Charge is Appropriate and Places Cost Responsibility Where it Belongs: On the Customer.

Schedule 80 imposes a charge on low power factor customers. (Ex. 570). This gives such customers an incentive to install capacitors to improve their power factor. (Hoff, Tr. 189-90).

SWAP opposed the charge, arguing that it is a "penalty"; that it is six times cheaper for Puget to install the capacitors than to charge the penalty. (Carter, Ex. T-58 at 17-18, referring to Ex. 65).

SWAP's rationale is unpersuasive and ignores the fact that Puget is <u>not</u> in a position to install capacitors in all instances, since power pole space is becoming increasingly unavailable, and underground service does not permit capacitor installation. (Ex. 65, Ex. 18, p. 70). In addition, installing capacitors at a substation is not a panacea. (Hoff, Tr. 1875).

Exhibit 66 does not dictate a different result. That exhibit does not reflect all costs to Puget. (Carter, Tr. 1767-68, Ex. 65). Second, Exhibit 66 is deceptive, since it does not reflect the fact that only very few customers that would have large capacitors. (Tr. 1770).

A customer with a poor power factor imposes capacity costs in Puget's system. (Hoff, Ex. T-8 at 59). These costs are not limited to the costs of capacitors. (Ex. 18, p. 61, 71-72). It is certainly reasonable for that customer to correct the problem. The power factor charge provides the incentive for the customer to do so. It should be approved.

I. <u>Miscellaneous Issues</u>.

A few rate design issues were presented on this record that justify policy guidance from the Commission.

A. Rates for Low Income Customers.

As Staff witness Sorrells stated, special rates for persons on low incomes likely requires legislation. (Ex. T-33 at 20). A low initial block in Schedule 7, and available conservation programs can help all customers, including those on low incomes. (Id.) BOMA's recommendation to have enforced contributions to the Warm Neighbors Fund (Saleba, Ex. T-54 at 18, Tr. 1714) is appealing but would violate Jewell v. Utilities & Transp. Comm'n, 90 Wn.2d 775, 585 P.2d 775 (1978). As the Commission is made aware in each rate case public hearing, as rates go up, the impact on the poor weighs heavier. Policy guidance from the Commission as to the advisability of legislative change or other initiatives would be desirable.

B. Hook-Up Fees and Conservation Rates.

Hook-up fees are charges imposed on a customer to cover costs imposed by the hook-up. Staff witness Sorrells identified this as an issue requiring further discussion. (Ex. T-33 at 19). Public Counsel presents a "cost based" residential hook-up fee of $200/kw proposal, as an incentive to encourage efficient energy choices by builders and ultimately consumers. (Lazar, Ex. T-43 at 56-64).

Staff believes this proposal may have substantial merit; the Company's concerns about whether the charge is in fact cost based were not well defined. (Hoff, Ex. T-83 at 21).

This may be an issue in which further study is needed.

A rate that prefers those customers who have completed a set level of conservation measures with their own funds was discussed by the Rate Design Collaboration Group; no consensus was reached. (Sorrells, Ex. T-33 at 21). Staff suggested that a rate that sends a marginal cost price signal may be adequate. (Id.) If the Commission disagrees, some policy direction would be appropriate.

VII. SPECIFIC RECOMMENDATIONS

Below is a summary of Staff's specific recommendations in this case. Staff recommends that the Commission adopt these recommendations and, as appropriate, require Puget Power to adjust its rate design filing in the following manner.

1. The peak credit method is an appropriate, recognized methodology for classifying production costs between demand and energy and should again be supported.

2. In future rate cases the use of gas, with a partial use of oil to account for one or more unusually cold weather peaking days in a test year, should be employed in assumptions about the data for the peak credit method.

3. The reflection of one-half of a combustion turbine and an 80% capacity factor for the combined-cycle combustion turbine under the peak credit method are appropriate.

4. Non-generation related transmission costs should be classified in the same manner as generation related transmission costs, using the peak credit method.

5. The basic customer charge approach should be maintained in classifying distribution costs.

6. The allocation factors for conservation costs should continue to reflect conservation as a resource, not as a class-specific benefit.

7. In calculating demand allocation factors, Puget should use a minimum of 200 hours to measure peak.

8. Puget has moved appropriately toward reflecting seasonal differentiation in generation and transmission costs.

9. Puget should be required in future cases to analyze differential risk between customer classes and propose appropriate customer and class-specific measures that address this issue.

10. The revenue requirement for the firm resale class should be addressed in the general rate case, Docket No. UE-921262.

11. Rates should move one-third toward parity.

12. For residential Schedule 7, Puget should move from three to two blocks, the second block should start at 400 kWh and a basic charge of $5.00 is appropriate. Also, a winter/summer differential of 10% is appropriate for Schedule 7.

13. Puget's proposed commercial Schedules 24, 25 and 26 are acceptable but the Commission should require Puget to continue to analyze whether Schedule 25 can be refined to avoid an energy rate that declines for some customers. A solution should be proposed in subsequent cases and should include a detailed consideration of Public Counsel's recommended "energy constrained demand charge."

14. Schedules 29 and 35 for seasonal irrigation and drainage pumping should be eliminated and a mechanism should be established to handle the BPA discount unless the BPA eliminates this credit.

15. The seasonal differentiation proposed by Puget in Schedules 31 and 49 is appropriate. Puget should be directed to conduct load analyses to determine the merits of a "summer peakers'" schedule or other rate design to accomodate summer peakers.

16. Puget's proposed interruptible rates for Schedules 36, 38 and 39 should be approved.

17. Schedule 43 (for schools) should be frozen, on conditions stated in Ex. 88.

18. The experimental marginal cost rate tariffs under Schedules 30 and 48 should be rejected and the Company should continue to discuss how such schedules could be successfully implemented.

19. The Schedule 80 power factor adjustment should be approved.

20. Policy guidance from the Commission as to the advisability of legislative change or other initiatives to address special rates for persons on low incomes is desirable.

21. Hook-up fees require further study.

22. Policy direction from the Commission on establishing rates which promote conservation is appropriate unless a rate that sends a marginal cost price signal is adequate.

VIII. CONCLUSION

The Staff's analysis of the cost of service study is consistent with prior Commission orders and policies on both the "peak credit" method, the classification of non-generation transmission to demand and energy, and the "basic customer" approach. There has been no significant showing that these orders and policies should not be continued.

There is a significant policy issue as to how quickly rates should move toward parity. We submit that a policy that balances gradualism with a move toward parity is in the long term best interest of both the ratepayers and the Company. The Commission will have to decide for itself how far toward parity rates should go, depending on the ultimate rate levels that will be authorized in the pending cases. From the Staff's perspective, a one-third movement toward parity is the most that is justified.

Rate design issues are as numerous as they are varied. The Staff, unburdened by either a profit motive or business self-interest, has offered rate design proposals that reflect proper price signals, are equitable and which otherwise meet established policies. Staff's recommendations should be accepted.

Respectfully submitted,

CHRISTINE O. GREGOIRE
Attorney General

DONALD T. TROTTER
Assistant Attorney General
WSBA No. 8752
Counsel for Washington Utilities
and Transportation Commission

July 9, 1993

C E R T I F I C A T E

I hereby certify that I have this day served a true copy of the foregoing document upon the parties listed below in this proceeding by mailing a copy thereof properly addressed to each such party by first class mail, postage prepaid.

James M. Van Nostrand
Attorney at Law
1800 One Bellevue Center
411 108th Avenue NE
Bellevue, WA 98004

Arthur A. Butler
Attorney at Law
1201 Third Avenue, Suite 2850
Seattle, WA 98101

Charles F. Adams
Assistant Attorney General
900 Fourth Avenue, Suite 2000
Seattle, WA 98504

Mark P. Trinchero
Attorney at Law
2300 First Interstate Tower
1300 SW 5th Avenue
Portland, OR 97201

Norman J. Furuta Associate Counsel
Federal Executive Agencies
P. O. Box 727
900 Commodore Dr., Bldg. 207, 2nd Pl.
San Bruno, CA 94066-0720

Carol S. Arnold
Attorney at Law
5400 Columbia Seafirst Center
701 Fifth Avenue
Seattle, WA 98104

Dated this 9th day of July, 1993.

DONALD T. TROTTER
Assistant Attorney General
Counsel for Wash. Utilities &
Transportation Commission