EXHIBIT NO. ______(DWH-4)
DOCKET NO. UE-92____________
WITNESS: D.W. HOFF

BEFORE THE
WASHINGTON UTILITIES & TRANSPORTATION
COMMISSION

COMPLAINANT

VS.

PUGET SOUND POWER & LIGHT COMPANY

RESPONDENT

EXHIBIT

Exhibit No. _______ (DWH-4)

FINAL REPORT

RATE DESIGN COLLABORATIVE

PUGET SOUND POWER & LIGHT COMPANY

FINAL REPORT
PUGET POWER RATE DESIGN COLLABORATIVE

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FINAL REPORT
PUGET POWER RATE DESIGN COLLABORATIVE

BACKGROUND

Puget Power sponsored the Rate Design Collaborative in order to assist it in responding to the Washington Utility and Transportation Commission's directive in UE-901183-T and UE-901184-P. That directive stated:

> **...the company should be ordered to make a rate design filing no later than April 1992. The Commission staff and other parties are encouraged to work with the company to ensure that the concerns of all parties are addressed in the filing and that the cost-of-service studies presented in the filing contain adequate information.**
>
> Docket No. UE-901183-T/UE-901184-P
> Third Supplemental Order, Page 24

GOALS

Based on the above, goals were established for the collaborative. They were to:

1) understand the concerns of the affected parties with regards to rate spread and rate design issues;
2) make sure that there is adequate information available in a rate proceeding to evaluate cost of service issues; and
3) aggressively pursue rate designs that encourage least cost planning.

In addition, at the first meeting of the collaborative, members were asked their objectives for the collaborative process. This resulted in a list of 28 items which ranged from statements about the use of marginal cost in rate design to a strong wish to see cost of service issues resolved. For instance, one of the items states that a positive result of the process would be that "The Commission explicitly states the approved cost of service method for Puget Power. . . "

ACTIVITY

The Rate Design Collaborative, consisting of the organizations listed below, demonstrated their high level of commitment and motivation by meeting 16 times (including full group and subgroup/technical meetings) between September, 1991 and March, 1992 to review cost of service, rate spread and rate design issues. This report documents the results of their work. The report briefly describes many of the concepts and issues raised by the members of the group. The appendix describes the specific concepts and issues that the group endorsed.

PARTICIPANTS

Boeing Company
Building Owners and Managers Association
Evergreen Legal Services
Northwest Cogeneration and Industrial Power Coalition
Northwest Conservation Act Coalition
Northwest Power Planning Council
Opportunity Council
Public Counsel
Puget Sound Power and Light Company
Rate Design Task Force
Washington Industrial Committee for Fair Utility Rates
Washington State Energy Office
Washington Utility and Transportation Commission Staff

CHRONOLOGY

April 1, 1991	-	Cause UE-901183-T and UE901184-P - Regarding A Periodic Rate Adjustment Mechanism
June 14, 1991	-	Puget Files Stipulation Regarding Incentive Plan For Least Cost Planning and Performance
June 20, 1991	-	Puget Kicks Off Collaborative, Surveys Participants For Ideas
September 20, 1991	-	Rate Design Collaborative Meeting - Charter, Organization, and Administration
October 25, 1991	-	Rate Design Collaborative Meeting - Marginal Costs
October 30, 1991	-	Subgroup Meeting - Cost Of Service
November 8, 1991	-	Rate Design Collaborative Meeting - Rate Design Proposals
November 12, 1991	-	Subgroup Meeting - Cost Of Service
December 5, 1991	-	Rate Design Collaborative Meeting - Low Income Rates/Credits and Residential and Commercial / Industrial Hook Up Fees
December 12, 1991	-	Subgroup Meeting - Cost of Service
December 20, 1991	-	Rate Design Collaborative Meeting - Cost of Service
January 6, 1992	-	Subgroup Meeting - Commercial and Industrial Rate Design Proposals
January 10, 1992	-	Rate Design Collaborative Meeting - Commercial and Industrial Rate Design Proposals
January 14, 1992	-	Subgroup Meeting - Residential Rate Design Proposals
January 14, 1992	-	Order, Cause UE-910689 - Incentives Plan For Least Cost Planning and Performance
January 24, 1992	-	Rate Design Collaborative Meeting - Residential Rate Design Proposals
January 30, 1992	-	Subgroup Meeting - Final Product of The Collaborative

February 7, 1992	-	Rate Design Collaborative Meeting - Review of Rate Design Task Force Interim Report
March 10, 1992	-	Rate Design Collaborative Meeting - Final Product of Collaborative
April 1992	-	Puget to File Rate Design Case

I. COST OF SERVICE AND RATE SPREAD

A. COST OF SERVICE CONCEPTS

Cost of service and rate spread issues were the subject of three subgroup meetings and three collaborative meetings. The subgroup was composed of experts in the field of cost of service and interested parties. Its task was to: (1) educate the collaborative regarding the technical issues of cost of service; and (2) evaluate the methods typically endorsed by the various parties and identify commonality.

The subgroup prepared and presented to the collaborative a report on areas of discussion and/or agreement regarding cost of service and rate spread. From that discussion, the group concluded it was important for the Commission to resolve cost of service issues which have been litigated and re-litigated in the past. To assist the Commission in this formidable task, the group agreed [1] to the following general points without agreement to specific details. In fact, it is expected that there will be different opinions on the details expressed during testimony presented to the commission. The general concepts endorsed by the group are:

1. Cost of service, as approved by the WUTC, should be a major factor in rate spread considerations.

2. For purposes of cost allocation (rate spread), forward looking embedded costs should be used.

3. The peak credit method will be utilized for classifying all resource costs.

4. Conservation costs should be treated as a resource. (There was no agreement on the classification and allocation of these costs. The allocation of DSM costs using class loads to which are imputed the kWh savings resulting from the DSM costs that are to be allocated was specifically discussed.)

5. General plant should be allocated on the basis of the results of allocating production, transmission and distribution plant.

6. Administrative and general expense (excluding salaries, regulatory commission expense, and outside service employed) should follow the approach filed by Puget Power in Cause U-89-2688-T, with some possible exceptions.

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1 While the Commission staff participated in the collaborative, nothing in this report should be construed to mean that Staff has agreed to any particular position in any future hearings.

7. If Federal income taxes are allocated to each customer class, they should be allocated in a manner that is derived from the allocation of ratebase to each class. This may not be acceptable if other than an equalized rate of return by class is approved.

Additionally, a personal computer (PC) based cost of service model was developed by the Company and a preliminary version distributed to the parties. This model was developed so that all parties could use the same model in a rate proceeding. This should help focus the testimony and discussion on cost of service principles rather than modeling techniques. A feature of this new cost of service model is that it will provide data sufficient for the determination of base and resource costs for each customer class.

B. DATA REQUIRED FOR COST OF SERVICE

In order to investigate the affects of cost of service issues, a number of data issues were reviewed. These issues include:

- Typical daily and hourly costs
- Class load profiles
- Seasonal differentials in energy and demand cost
- Value of interruptible load
- Cost of correcting poor power factor

Data were provided for the first three issues and studies are under way to analyze the last two issues.

II. MARGINAL COST

The Collaborative reviewed the status of Puget Power's marginal cost studies and discussed the role of marginal costs in rate spread and rate design. The group agreed to continue the traditional practice of classifying production costs into energy and demand components using the peak credit method based on the marginal production plant. That is, the group decided that the concept of using forward looking embedded costs (through application of the peak credit method) was suitable for cost of service and rate spread analyses and that marginal cost should be a factor in rate design. However, it was felt that implementing marginal cost based pricing is difficult. This is discussed in the Section III, Rate Design. The Collaborative decided to concentrate on marginal production costs. The marginal production costs will be based upon the avoided cost filing. The time frame, short versus long run, will be dependent upon the specific rate design.

Puget Power's marginal production costs are currently based upon splitting the next resource in the least cost plan using the peak credit method. There was discussion about whether the Bonneville NR rate is the correct basis for splitting the resource cost into energy and demand components and whether Puget's "marginal" resources developed in the Company's least cost plan should be used for this purpose.

III. RATE DESIGN

Much of the Collaborative's effort focused on the area of rate design. Initially, all participants identified areas of interest regarding proposals for new rate designs or changes to existing rates. These proposals have been categorized by sector, residential or commercial/industrial in nature. However, some proposals are common to both categories.

The following is a brief overview highlighting the major discussions on rate designs. It does not reflect a consensus view of all parties, unless so stated, nor a complete record of all discussions.

A. RATE DESIGNS FOR ALL SECTORS

1. Incorporate Marginal Costs In All Rate Schedules

The proposal that all rate schedules should be designed to reflect Puget Power's marginal costs raises a number of issues. First is the very fundamental question of the importance of the price signal. There was a general sense that the price signal is necessary, but not sufficient for promoting conservation. The collaborative generally had the philosophy that the price signal needs to be coupled with conservation and public awareness programs. Regardless of the persuasion of the price signal, there was a feeling that the price signal must be consistent with the conservation signal. Second is the question of whether short or long run marginal cost should be used. It was generally accepted that long run marginal costs should be used in some instances, although the precise number of years that constitute the "long run" was never determined. Third is the issue of matching revenue requirements. All rates cannot be set at long run marginal cost because the revenue requirement would be exceeded. One approach is to set the tail block at marginal cost and reduce the prior block(s) and/or customer charge to match the revenue requirement. This is not difficult to do in the residential sector. However, it is more difficult to give individual customers a marginal tail block in the commercial and industrial sectors, due to the large variation in consumption. This issue is addressed in the discussion concerning each individual sector's design.

2. Super-Saver Rate

This proposal called for either a separate rate or rebate for all customers who have fully participated in all cost effective conservation programs available to them from Puget. A variation on the proposal was to limit the rebate/discount to customers who funded their own conservation. The argument for the latter approach was that the customers participating in Puget Power programs already benefit from both receiving the measure at low/no cost and from lower electric bills.

3. Seasonal Energy Rate Difference

One proposal called for continuing the summer/winter seasonal energy rate difference based upon current market cost differences. The current market cost difference between the two seasons (adjusted for losses) is approximately 4-6 mills/kWh (bus), or about 10%. There may also be seasonal capacity cost differentials that have not yet been quantified.

4. Distribution of Low-Cost Hydro Resource

Some members of the collaborative believed the benefits from low cost historical hydro resources should be available to all customer classes. However, there was some disagreement on the allocation method. While some felt the current practice of allocating hydro like any other resource was correct, an alternative proposal called for the inter-class percentages to be fixed over time so that a class's share does not become reduced by greater growth in another class.

5. Conservation Cost Recovery and Fuel Switching

The issue whether there needs to be alternative mechanisms to recover conservation costs from a customer who converts to other fuel sources following receipt/installation of Puget Power's conservation services/programs was discussed. Alternatively, the issue of whether Puget Power should be encouraging gas conversions was raised. The issue of fuel switching was referred to the Technical Collaborative group.

B. RESIDENTIAL RATE DESIGN

There were discussions regarding the energy charge and monthly charge along with ancillary rate designs. The energy and monthly charge are discussed separately in an attempt to clarify the issues. Many of the competing proposals that combined the energy and monthly charge appeared to have similar results with regards to the total bill of a typical residential customer. However, the diverging structures of the rate's components reflected disagreement on both the theory and cost basis that supported the structure along with different perspectives on what was equitable.

1. Energy Charge

One option discussed was to switch to a two block inverted energy rate. This proposal would collapse the number of energy blocks from three to two. The price and/or size of block for the two blocks was also discussed.

One option would apply rate increases (such as PRAM and general) to the second block until it reaches marginal cost. This approach assumes a first block of 600 kWhs. The effect will be to provide the marginal price signal to a broad cross section of customers rather than just the space heat customers.

Another proposal would "re-block" the energy rate at a lower threshold, say 200 kWh, and set the remainder of the consumption (or second block) at marginal cost. The first block rate would be lower than average cost. The current melded rate for the second and third step is 5.73 cents/kWh. The current estimate of marginal costs is 6.5 to 7.5 cents/kWh.

The discussion of blocking for the energy component of the residential rate, and incorporating a marginal cost price signal, inevitably involved the basic charge component of the rate as well. Competing proposals called for lowering either the first block or the basic charge while increasing the tail block rate. Overall effects were evaluated in combination with various proposals for the basic charge (ranging from $0 to $15 per month). The range of prices reflects the range of options as to the right customer related portion of cost of service.

The discussion about the structure of the residential rate (and other rates) considered the traditional ratemaking objectives outlined by Bonbright and others. These goals (particularly those of efficiency, equity and gradualism) often seemed disparate and incongruous to the collaborators. For example, while a given design may provide the "correct" price signal, it may not adequately address the concerns of equity and welfare. As a consequence, least cost planning goals applied to ratemaking may conflict with equity goals for certain customers.

The seasonality in residential energy rates was discussed. Seasonality was considered from two perspectives: differences in energy costs from summer to winter (in the range of 4-6 mills); and seasonal differences in demand-related costs. The collaborative noted that these concepts can be reflected in the design of a residential rate in a variety of ways such as selection of the block size (i.e., level of inversion) or price of the block (i.e., winter rate 6 mills higher than the summer rate).

2. Basic Charge

There were areas of disagreement in this area with proposed charges ranging from no charge, to the basic customer charge currently used, to a distribution system access charge. There was also a proposal for a "disappearing minimum" charge. There was discussion as to the elements or accounts that should be included in the basic charge component of the residential rate structure. There was discussion that a basic customer cost concept, if used as the basis for the basic charge, should include the fully distributed costs of meter, service drop, meter reading, and customer billing. Several members thought the concept of the basic customer charge should include some components of customer service expense and transformer costs, at a minimum.

3. Interruptible Water Heat Rate

A number of variations for an interruptible water heat rate were discussed along with the associated economics. A pilot program for an interruptible water heater rate was discussed. In order to avoid inadvertent load retention, the collaborative believed that the test should be offered in an area not served by gas. In theory, the experiment would allow Puget to gain experience with implementing, fielding, and operating this type of program.

4. Weatherization Incentive Rate

The collaborative considered a number of rate related approaches to promoting conservation in multi-family dwellings. The proposals were designed to create additional economic incentives for customers to participate in Puget Power programs. Although innovative solutions to the problem of low participation rates by landlord were proposed, it was questioned whether a landlord would simply pass any additional costs back to the tenant through increased rents.

One proposal would split the tenant's bill into two parts. The landlord would receive and be responsible for one part until the landlord has participated fully in the Puget Power audit and weatherization program. The proposal is intended to give the landlord the incentive to participate in order to lower or avoid a portion of its own bill.

Another proposal included a surcharge to the multi-family building landlord each time a tenant signed up for service unless the landlord has participated in a Puget Power audit. This proposal would be linked to changes in the conservation programs designed to make the program more attractive to the landlord.

Another suggestion was to unbundle the financing of conservation measures so that Puget Power would pay the landlord the avoided cost of each measure up to a maximum of 120 percent of the measure's cost on a measure-by-measure basis.

5. Conservation Incentive Rate

One proposal would provide a 5-15% discount on all usage in the tail block(s) by customers who have installed all cost-effective conservation measures identified in a Puget audit. The rate would be available only to customers who didn't receive a "substantial" amount of their installed conservation from Puget Power.

Details discussed but left unresolved were: (1) who would pay for/conduct the audit; (2) would the audit be valid for a particular time frame, after which the customer must re-qualify (another audit) for the rate; (3) does the audit need to be at the same level of detail as Puget Power's current audits; and (4) could this be designed so as to be an incentive to the multi-family landlords to invest in conservation measures in their rental units.

6. **Green Rate**

Two versions of this rate were discussed during the process. The original proposal called for a voluntary rate where customers agree to pay the incremental cost associated with providing all their energy from environmental benign generation. The company would use the payments to modify its resource acquisitions to reflect those customer preferences. An alternative proposal was offered where the green rate would be the default and customers could elect the brown rate which was cheaper initially, but contained the risk that those same customers would have to pay future clean-up costs for those "brown" resources.

Issues raised during this discussion included the complication of the least cost planning process, free riders, the accounting for green resources over time and whether "green" went with the meter or the customer.

7. **Low Income Rate**

The low income issue was discussed by collaborative members. Activity focused on understanding the extent of the problem in Puget Power's service territory, current programs that address the issue, approaches being used or proposed by other utilities across the nation, and other non-utility or non-rate solutions to the problem.

There was discussion on alternative rate designs and the merit of income based credits versus a percentage discount on the bill. However, it was believed to be premature to discuss the specifics of a rate design for low income until all parties agreed to (or the Commission ordered) a specific policy.

The cost basis for a low income program or rate was discussed. A portion of the cost might be offset by a decrease in account write-offs (uncollectables) and associated costs of disconnection and collection actions. Some rough assessments suggest that the associated rate increase for other customers would be "relatively small".

One proposal was to seek Commission guidance as to the role for electric utilities in general, and Puget Power in particular, on the issue of low income assistance. An alternative proposal was to direct the low income rate assistance problem to the state legislature.

The collaborative also discussed alternatives other than rate structure changes to assist low income customers. These alternatives include targeting cost effective weatherization and conservation measures to this customer group.

8. Hookup Fees

Proposals for residential hookup fees for site built and manufactured housing were discussed. The connection charge for new structures was proposed as a stick to encourage customers to incorporate cost-effective conservation measures (especially lost opportunities) that exceed current building code requirements.

There was discussion but no agreement on whether there were cost effective measures for site built housing that both exceeded code and could be effectively enforced/administered at the time of the new hookup.

There was consensus that there are cost effective conservation measures that exceed code for new manufactured housing. The need for hookup charges was evaluated in conjunction with the regional Manufactured Housing Assistance Program, which will provide incentives to the manufacturer.

C. COMMERCIAL / INDUSTRIAL RATE DESIGNS

1. Standby Rate

This proposal generally provides a discounted demand charge associated with serving native load for self-generators under the following conditions: (1) scheduled maintenance coordinated with Puget Power; and (2) limited forced outages during non-system peak periods. Standby customers would be required to pay the full cost of transmission and distribution facilities dedicated to their facility.

There was discussion on how the rate would work for forced outages occurring during periods of extreme or severe system stress. It was discussed that the price charged for services at these times must be priced according to its value. The option for firm and non-firm standby was also raised.

2. Interruptible Rate for Large Loads

There was a discussion about the need to establish a range of interruptible rates in order to offer more flexibility than under current schedules. A range would accommodate different levels of interruptions and be available to more customers. The valuation of the interruptions and the associated pricing was also discussed.

Conceptually, the interruptible rate proposal includes a discount on demand charges for customers signing up for the interruptible rate and a credit for reduction in energy (kWh) during the interruption periods. The credit may be in the form of $/kWh, or $/month, or $/interruption. The amount of demand, length of contract, notification period for interruptions, length of interruptions, and frequency of interruptions need to be determined, with the long-term objective of offering a menu of options to the customer, priced at each option's value to the power system. Interruptions would not be voluntary and penalties would exist for customers failing to meet contracted demand reductions. The length of the contract and contract parameters would consider both utility and customer needs. There was also discussion about the conditions under which there would be no payment for interruptions.

There was discussion as to the valuation of the interruption with ranges in value from short-run marginal capacity costs (as reflected by Puget Power's recent capacity contracts) to long-run marginal capacity costs (as reflected by the cost of new resources).

3. Voluntary Peak Curtailment Rate

This proposal would establish a rate that allowed for payment to customers on an energy (kWh) basis for voluntary curtailments when the utility calls for curtailment. There would be no penalties for non-compliance. The impacts of a customer's willingness to curtail without compensation during critical periods was raised but not quantified.

4. Marginal Cost for Large Power Users

There was a discussion that the marginal cost price signal should be incorporated into rates for large commercial and industrial customers, if possible. However, it was difficult to reach agreement on the mechanism and timing. Most of the proposals incorporated developing a tail block that is customer specific as the means for dealing with the large divergence in consumption among large customers, while allowing for each customer to receive a marginal cost price signal.

One proposal called for a rate based upon an historical rolling bench-mark. An alternative rate called for using historical consumption to set a two block rate for each customer and that takes into account "known and measurable" load fluctuations that can be anticipated during the duration of the contract. The tail block would be set at the Company's marginal cost, and would change based on changes in the Company's marginal costs rather than changes in its general or PRAM revenue requirements. These proposals are designed to accomplish the following goal: the customer would see no change in their bill if its consumption remained constant, and would pay marginal cost for increases in consumption and enjoy marginal cost savings for decreases in consumption.

The collaborative discussed the merits and rationale for making the rate voluntary versus mandatory including potential legal issues.

5. **kVarh Rate Modification**

The Collaborative believed that the current rates charged for kVarh should be reviewed to ensure that they reflect the company's cost of correcting poor power factors. This would apply to Puget Power's existing Schedules 24, 29, 31, 35, and 43.

6. **Breakup of Schedule 24**

The Collaborative discussed establishing two or three rate classes for customers served under the existing Schedule 24 (Secondary Voltage General Service). The two rate class proposal would split customers on the basis of whether they are demand metered. The three rate class proposal would split the demand metered group further into small and large energy use customers. The basic charge, energy rate and demand rate (if needed) would vary by class, in recognition of the variance in each class's respective customer, energy and capacity cost of service.

The basis for the recommendation was to: (1) provide more effective price signals to customers; (2) eliminate the perceived declining energy rate of the current structure; and (3) refine the cost allocation to a diverse customer class.

7. **Phase Out of Inefficient Street Lighting**

A proposal to increase rates for inefficient street lighting was discussed. The proposed rate was directed at eliminating the use of incandescent and mercury vapor street lights and give customers (whether using Puget or customer-owned equipment) the incentive to convert to more energy efficient lighting, such as high pressure sodium vapor lights. A review of information documented the declining inventory of mercury vapor and incandescent street lights on Puget Power's system and Puget Power's current plan to convert the remaining Company-owned mercury vapor street lights by the end of 1992. Many felt that a special rate was not needed if the program was effective, although some would like to see a stronger program aimed at customer-owned mercury vapor lamps.

8. **Interruptible Rate for Water Heat**

The group discussed having an interruptible water heat schedule for commercial customers as well as residential customers. (See the discussion under the residential sector.)

9. Time / Seasonal Demand Charges

One proposal would separate the demand component of the rate structure into two components: (1) distribution and local transmission facilities related charges on a monthly basis; and (2) production, generation-integration and network transmission related charges during the system peak period (e.g., the winter period).

10. New Large Loads

A party made several proposals regarding new large loads. They were to require prepayment or a performance bond for the entire cost of customer specific transmission and distribution expenditures, charge long run incremental cost for all portions of new large loads over three megawatts, and require formal advance notice of any large increase or decrease in loads. Some members felt these proposals would adversely affect economic growth and questioned their relevance to Puget's planning requirements.

11. Commercial / Industrial Hook Up Fees

One proposal would implement a commercial hookup fee based on the customer's connected load. This proposal called for the fee to be decreased or eliminated based upon the customer adopting a portion or substantially all of Puget Power Design Assistance recommendations.

APPENDIX A

CONCEPTS ENDORSED BY THE COLLABORATIVE

This section presents concepts that were endorsed by the Collaborative. Details are provided for proposals where the Collaborative could reach consensus beyond general concepts. While there was consensus on items specified, endorsement of concepts does not necessarily mean agreement on details and items not specified. It is expected that members of the Collaborative will provide their own witness(es) to elaborate on how they believe the concepts should be implemented.

1. Experimental Rate Design Group

Some of the proposed rate changes are experimental. In order to assist the company in conducting these experiments, an Experimental Rate Design group will be formed. The group will assist the Company in the preparation of the experiments, the analysis of the results, and the creation of future experiments. Puget Power will continue to utilize customer involvement to assist in the development and review of these rate designs.

2. Guidance on Issues

The Collaborative feels that clear guidance on cost of service (COS) and rate design policies in the rate design filing is essential. In order to assist the Commission as much as possible, the parties will work together to focus the Commission's attention on issues the parties feel are most important. This does not imply that parties have agreed to constrain the substantive recommendations that they may wish to present to the Commission on cost of service issues.

3. Model

All parties to the case will use the Company's PC based cost of service model. Puget Power will provide technical assistance.

4. Rate Spread

Cost of service, as it is approved by the WUTC in this case, should be a major factor in rate spread considerations. These considerations should include establishing parity guidelines.

5. Forward Looking Embedded Cost

For purposes of cost allocation (rate spread), forward looking cost relationships should be used to classify the embedded cost of service or revenue requirement in order to correctly provide price signals to the customer.

6. **Peak Credit**

The peak credit method will be used to classify all resource costs.

7. **Conservation Costs**

Conservation costs should be treated as a resource. (There was no agreement on the classification and allocation of these costs. The allocation of DSM costs using class loads to which are imputed the kWh savings resulting from the DSM costs that are to be allocated was specifically discussed.)

8. **General Plant**

General plant should be allocated in a manner that is derived from the allocation of production, transmission and distribution plant.

9. **A & G**

Administrative and general expense (excluding salaries, regulatory commission expense, and outside services employed) should follow Puget Power's traditional approach. This does not preclude parties raising exceptions to this guideline at some future date.

10. **FIT**

If Federal Income Taxes are allocated to each customer class, they should be so allocated in a manner that is derived from the allocation of ratebase to each class. This may not be appropriate if other than an equalized rate of return by class is approved.

11. **Residential Rates**

a. Basic charge shall be adjusted if needed in the 1992 general rate case to cover the current fully distributed cost of meters, service drops, customer billing, and meter reading.

b. The current block structure shall change in the 1992 general case by reducing the current three block structure to a two block structure.

c. All PRAM (Schedule 100) revenues allocated to the residential sector in PRAM cases between the 1992 general rate case and the next general rate case will be applied as an equal cents per kWh to the last block, until long run marginal cost is reached. When long run marginal cost is achieved, rate increased will be applied to the first block.

12. Residential Pilot Water Heat Interruption Rate

a. The rate discount will reflect the net value to Company of interruption (such as capacity and energy costs avoided less expected cost of mature program).

b. The pilot program will be conducted so that it does not intentionally encourage load retention or discourage fuel switching.

c. Puget Power will start work on developing the pilot program immediately. The pilot program will be implemented upon approval of the WUTC (given a reasonable time to set up the program).

d. Pilot program costs will be treated as a resource cost for the purposes of PRAMs.

13. Residential Weatherization Incentive.

While this is not a rate design issue per se, possible methods of increasing the penetration of multi-family weatherization were discussed. The group agrees to forward the following concept to the Technical Collaborative for their consideration:

> Landlords will be offered cash payments if they weatherize their rental units. The current payment schedule will be reviewed to determine if an alternative scheme can be developed that increases the incentive to participate while still being cost effective for all rate payers.

14. Residential Hookup Fees

The collaborative agrees that a hookup fee for manufactured homes should be part of a regional program that includes payment from BPA for the Manufactured Housing Acquisition Program (MAP). That fee would have the following characteristics:

a. The hookup fee would apply to new manufactured homes that do not meet standards recommended by the Regional Council under the MAP.

b. The fee should be consistent with manufactured housing hookup fees being proposed by other utilities in the region.

15. Interruptible Rates For Large Loads

a. Voluntary tariff includes discounted demand charges, credits for curtailed energy, and penalties for failing to interrupt. All large load customers are eligible, regardless of schedule.

b. Schedules 43 and 46 will be frozen. Customers currently on these schedules will be grandfathered.

16. Voluntary Peak Curtailment Rate

a. This rate is not a reduction in existing rates but a credit payment for load curtailed.

b. The credit payment is based on the expected value of the interruption to the Company, less the processing cost for verifying the curtailment.

c. There is no penalty for non-compliance.

d. Customers pay incremental metering costs, if any, on a monthly basis.

17. kVarh Rate Modification

Rate will be updated based on Puget Power's cost of correcting for poor power factors.

18. Nonresidential Secondary Service (Schedule 24)

a. Establish three rate schedules for non-residential secondary service, replacing the existing Schedule 24.

b. Schedule 24A - Expected demand less than 50 kW. No demand meter. Demand costs included in energy rate. Basic charge.

c. Schedule 24B - Expected demand between 50 kW and 350 kW. Demand and energy meter. Flat rate on both demand and energy. Basic charge.

d. Schedule 24C - Expected demand greater than 350 kW. Demand and energy meter. Flat demand and energy rate. Basic charge.

e. All schedules would have rates based on their cost of service.

19. Seasonal Demand Charges

a. The demand charge would be based on two components.

b. One component would be for distribution and local transmission facilities-related costs, and would be the same rate every month.

c. A second component would based upon seasonal differences in production, generation-integration and network transmission-related costs.

Puget Sound Power & Light Company
Docket No. UE-920499
Response to Staff Data Request Number 10

Request:

Re: Exhibit No. ___ (DWH-5), Schedules 24, 25 and 26. Please provide data supporting why the seasonality difference is 10% for Schedule 24 compared with the seasonality difference (50%) for demand charges in Schedules 25 and 26.

Response by Mr. Hoff:

The seasonality differences are discussed in Exhibit No. T-8 (DWH -1) at pages 12, 13, 20, 21, 60 and 61. We followed the existing procedure of establishing a percentage differential for energy (which has been updated in this case to 10%) that is consistent throughout all schedules. As mentioned in the testimony, the 10% differential is roughly the difference in the company's avoided cost data between summer and winter, when serving a water heat customer. (See answer to Staff 6 -- 5.7496/5.2038 = 1.10). As also mentioned in the testimony, this difference is also consistent with recent "normal" differentials in seasonal values of power. This differential does not consider distribution costs. The differential is not meant to be a precise reflection of actual variations in seasonal marginal production costs at any point in time, primarily because such differentials are dependent on the cost that is assumed to be avoided, which can constantly change. It is meant instead to be a rough estimate of the magnitude of difference between the seasons. The 50% differential in the demand rate is a similar rough estimate of magnitude which reflects the impacts of coincident and non-coincident costs on a demand charge, and is new to this filing. It is meant to address seasonality of demand when demand is not included in the energy charge, as it is in schedule 24. The impact of seasonality on demand charges, when isolated from energy charges, is much greater than when included in the energy charge.