EXHIBIT NO. ___(JAH-1T)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: JAMES A. HEIDELL

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-06____ Docket No. UG-06____

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JAMES A. HEIDELL ON BEHALF OF PUGET SOUND ENERGY, INC.

FEBRUARY 15, 2006

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is James A. Heidell and my business address is 390 Interlocken Crescent, Broomfield, Colorado 80021. I am employed by PA Consulting Group (PA) as a Managing Consultant.

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(JAH-2).

Q. What is the purpose of your testimony?

A. I am sponsoring the Company's electric cost of service study, electric rate spread and rate design results, and the application of the Company's electric weather normalization methodology to the rate design.

The Company provides two electric cost of service studies in this case. The first is the Company's recommended cost of service study methodology. The second study is provided for informational purposes and follows the methodology of the last Commission-approved electric cost of service study – commonly referred to as the "Commission Basis" methodology – which applies the cost of service methods approved in the 1992 generic cost of service case under Docket No. UE-921262, the last time the Company's electric cost of service study was litigated through to a Commission order.

As detailed in my testimony, the Company's preferred electric cost of service approach reflects changes both in PSE's power supply situation and in PSE's data collection systems that have occurred since the last time the electric cost of service was fully litigated over a decade ago.

My testimony also presents the Company's proposed electric rate spread proposal. As with past cases, the Company continues to advocate rate spread proposals that result in aligning cost causation with cost recovery responsibility. The theoretical point where costs assigned to a customer class equal the revenues collected from that customer class is called "parity." The ongoing application of the Company's policy of moving toward parity has resulted in all but two classes now being within 5% of parity. The Company acknowledges that the determination of parity is not absolute and that parity is dependent on the methodology used to allocate joint costs. As a result, the Company's proposal in this case does not rigidly move each class to parity.

Finally, I present the Company's rate design proposal. No major changes to the existing rate structure are proposed. However, the Company is introducing a residential experimental rate that provides a cost savings incentive for customers to reduce demand during critical demand / high cost market periods, as described in the testimony of Mr. Calvin E. Shirley, Exhibit No. ___(CES-1T).

II. ELECTRIC COST OF SERVICE

A. Background Regarding Electric Cost of Service Studies

Q. Please summarize the purpose of a cost of service study.

A. A cost of service study is used to identify the costs that are incurred to serve a particular customer class. Identifying the cost responsibility of each class requires an analysis of all the Company's costs and then allocation of those costs to each rate class. This allocation is done by first directly assigning the costs to a rate class, in cases where it can be determined that the costs are caused by that rate class alone. Joint costs that are shared by multiple customer classes are then allocated to various rate classes on a pro rata basis. Washington State utilities have historically prepared these cost studies based upon embedded costs rather than marginal costs. However, this Commission has been receptive to the use of forward looking cost allocation factors when allocating costs to various rate classes.

The ultimate objective of the cost allocation process is to create a just, fair, and reasonable allocation of costs to different customer classes. This cost of service information is then used to allocate the revenue requirement determined in a rate case to the different customer classes. Historically, the Commission has treated the cost of service study as a "guidepost" for the allocation of the revenue requirement and has eschewed the mechanical application of the cost of service study.

The cost of service study also serves as a guide for the rate design process. For example, the customer charge has historically been based upon customer costs determined in the cost study. In addition, demand charges for the non-residential rates have historically been guided by the determination of demand costs in the cost study.

Q. Please summarize the process for preparing the electric cost of service study.

A. The cost study starts with the electric revenue requirement that is set forth in the testimony of Mr. John Story, Exhibit No. ___(JHS-1T), which represents the Company's costs to provide service to its electric customers.

The first step is to separate these costs into the major electric utility functions: generation, transmission, and distribution. This process is referred to as functionalization of costs.

The second step is to further divide the costs associated with each of the major functions into customer, demand and energy components (which are explained below). This process is referred to as classification.

The third step is to allocate each of the cost components to the individual rate classes.

Q. What are "customer, demand and energy" costs?

A. *Customer* related costs are incurred to connect a customer to the electric distribution system, meter and meter reading costs, billing, and customer service. Customer costs are a function of the number of customers served or costs that are incurred whether or not the customer uses any electricity.

Demand related costs are associated with electric plant that is designed, installed and operated to meet maximum hourly or daily electric capacity requirements, such as transmission and distribution cables and related structures. While these facilities may not be fully utilized at all times, they must be designed and installed to meet the maximum load that is anticipated for the facilities.

Energy related costs are those costs that vary with the amount of electricity sold to, or transported for, customers. Costs related to electric supply are classified as energy related to the extent they vary with the amount of electricity purchased by the utility for its electric sales customers.

One of the challenges of the classification of costs into demand, energy, and customer components is that some utility equipment is commonly considered to serve multiple functions. Generation equipment is widely recognized as having both demand and energy components. The demand component reflects the cost of capacity to serve peak demands.

Q. How does one go about performing the three steps described above?

A. The Company bases its classification and allocation of costs upon supporting studies aimed at properly matching cost causation with cost assignment. The methodology and studies used to perform the classification and allocation of costs can be controversial since it involves allocation of joint costs. Furthermore, the selection of the process used can have a significant impact on the determination of where a customer rate class is in relationship to parity (the theoretical point where costs assigned to a customer class equal the revenues collected from that customer class).

B. <u>Overview of the Company's Proposed Electric Cost of Service Study</u>

Q. Is the Company proposing to change the Commission approved methodology for classification and allocation of electric costs?

A. Yes. The Commission last addressed the Company’s cost classification and allocation methodology in a fully litigated case in Docket Nos. UE-920499 and UE-921262. In Docket No. UE-920499, the Commission reviewed only rate design issues and this docket is referred to as the "Electric Rate Design Case." In a companion case, Docket No. UE-921262, the Commission implemented the results of the Electric Rate Design Case as well as addressing other rate case issues. As a result of changes that have occurred in the thirteen years since this "Commission Basis" case, as discussed below, the Company is requesting that the Commission approve the following changes in PSE's electric cost of service methodology:

- Modification of the approach used to classify generation costs into demand and energy components;
- Modification of the approach used to classify transmission costs into demand and energy components;
- Modification in the number of system peak coincident hours used as the basis for allocation of generation and transmission demand costs to each of the rate classes;
- Allocation of distribution substation and line costs relative to each class's share of the load on those specific facilities;
- Direct allocation of line transformer costs to each of the customer rate classes;
- Classification of the transformer cost as customer related rather than demand related;
- Direct allocation of distribution costs to the Schedule 40 rate class consistent with the Schedule 40 tariff approved in the 2004 general rate case, Docket Nos. UG-040640 et al.

Q. What are the implications of the proposed changes?

A. The numerical impacts of the proposed changes are shown in the parity ratios set forth in the following table. The middle column shows the parity ratios based upon the Electric Rate Design Case methodology while the right-hand column reflects the Company's proposed changes to that methodology. As is evident from the table, the changes produced by PSE's proposed methodology are modest. While a detailed attribution of the changes between the two methodologies was not performed, the changes are primarily attributed to how the system's distribution costs are allocated.

Customer Class	**Parity Ratio Commission Basis**	**Parity Ratio PSE COS**
Residential	100%	99%
General Service, < 51 kW	100%	100%
General Service, 51 – 350 kW	101%	105%
General Service, >350 kW	98%	103%
Primary Service	94%	97%
Campus Rate	101%	100%
All Electric Schools	91%	97%
High Voltage	101%	103%
Lighting Service	98%	99%
High Voltage – Retail Wheel	111%	110%
Firm Resale	129%	130%
System Total / Average	100%	100%

Under the Company's proposed rate spread and rate design proposals there will not be any dramatic changes to customer cost allocations as a result of the proposed cost of service changes.

Q. Why is it important to review the cost of service methodology if the results do not change significantly?

A. An accurate assignment of cost causation is important to the underlying expectation that the rates paid by customers are fair. In addition, an accurate representation of cost causation is important for understanding the economics of providing electric service to customers and the implication of programs such as demand side management.

Q. Please elaborate on why the Company believes it is appropriate to review cost of service issues that were previously resolved in the Electric Rate Design Case.

A. The Company's last fully-litigated cost study was filed with the Commission in 1992 in Docket No. UE-921262, et. al. In subsequent cases, the Company settled all issues with respect to cost of service with intervening parties without specific findings on cost of service. Consistent with WAC 480-07-510(3)(b) and the terms of such settlements (which typically state that the settlement is not to be viewed as agreement with or used as precedent for particular methodologies), that means the last so-called "Commission Basis" cost study is based on data that are over a decade old. Numerous changes have occurred over the past 13 years that justify the Commission revisiting certain aspects of the electric cost of service addressed in the last Commission-approved study.

While the Company is mindful of the need to efficiently use resources and not re-litigate resolved issues, the Company also has a duty to update cost allocation procedures when they become stale as a result of changing circumstances. The Commission's Ninth Supplemental Order on Rate Design Issues in Docket No. UE-921262, et. al, states: "The Commission does not, however, accept the Company's invitation to designate Puget's model to be used as the standard in future proceedings. As circumstances change, and theories evolve, other approaches to cost of service analysis may prove to be relevant."

Over a decade later, the power markets have changed and new approaches are relevant. As a result, I will discuss changes made in the Company's proposed cost of service study to account for how electricity is bought and sold in today's marketplace. The proposed approach also changes the allocation of transmission costs to better match with open access and wholesale transmission pricing. Finally, the Company's cost of service study presented in this case uses the distribution cost allocation proposed in PSE's 2004 general rate case in order to match cost allocation to cost causation.

Q. Will the model used to develop the cost of service studies be provided to the parties to the rate case?

A. Yes. The Company is using the Navigant cost of service model for both the gas and electric cost studies. In its 2001 general rate case, the Company used the Navigant cost of service model for the gas study and the Company-developed cost of service model for the electric study. The Company's electric cost of service model was developed in the late 1990s and has been in use since that time. In an effort to standardize the cost of service models used by the Company, the Navigant cost of service model is used for both the electric and gas cost of service studies in this case. The Company will work with parties needing access to this model so they can obtain a temporary license from Navigant for use of the cost of service model in conjunction with this rate case.

C. Classification of Generation Costs

Q. Please describe the Commission Basis approach to classifying generation costs into energy and demand components.

A. The Commission Basis approach has roots dating back to the early 1980s.[1] In 1992, the Commission's order in the generic cost of service/rate design proceeding accepted the Company's proposal to continue to use the "peak credit" methodology to divide generation costs into demand and energy components.[2] It is my understanding that the peak credit method is unique to the Northwest,

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[1] The Company used the "peak credit" method in Cause U-83-28. However, that method is significantly different than the current implementation approved in the Rate Design Case. In Cause U-82-28, capacity resources were allocated 100% to demand. Resources that supply both energy and capacity had a separate peak credit calculation for thermal and hydro resources that appears to rely on embedded costs.

[2] Docket Nos. UE-920433 & UE-920499 Ninth Supplemental Order on Rate Design Issues, p. 7.

although the genesis of the method (analyzing capacity cost relative to base load cost) is shared by a number of commonly used cost classification methodologies.

Specifically, the current peak credit method classifies electric production costs as either energy or demand based on the ratio of the cost of a simple cycle turbine (CT) to a combined cycle combustion turbine (CCCT). The calculation of the cost of the CT is based upon fifty percent of the capital and fixed costs plus the fuel costs based upon two hundred hours a year of operation. The calculation of the CCCT is based upon the full costs of a combined cycle turbine operated as a base load unit. Both the numerator and denominator of the ratio are expressed in $/kW year. The fuel cost used in the numerator is based upon firing the unit for 150 hours with natural gas and 50 hours of fuel oil. The use of fifty percent of the capital and fixed O&M of the CT was not based on detailed analysis, but was proposed in recognition that the turbines provide other functions including hydro firming.

Q. How is the Company proposing to change the peak credit method?

A. PSE is proposing a number of changes that are intended to better reflect the relative cost of capacity in PSE's current electric portfolio. These changes include: (1) using 100% of the capital and fixed cost of the CT; (2) removing the use of oil in the calculation; (3) adjusting the average annual gas price to reflect cost of gas during extreme peak periods; and (4) reducing the number of assumed hours of the CT's operation from 200 to 75 hours.

Q. What is the result of your proposed changes to the peak credit calculation?

A. It changes the percent of production cost allocated to demand from 13% to 20%. I have provided the calculation in Exhibit No. ____(JAH-3).

Q. What is the rationale for moving from 50% of the CT's fixed cost in the peak credit calculation?

A. Use of only half the cost of a CT was a qualitative judgment made over a decade ago based on assumptions of how the CT's cost reflected power planning strategies and markets that existed in the early 1990s. The power markets have changed over the last thirteen years, as have the Company's planning strategies. Specifically, the changes that lead me to conclude that the full cost of the CT is a better proxy for capacity cost include: (1) the decreased role of hydro resources in meeting PSE's total energy requirements; (2) the decreased role of the hydro contracts in meeting PSE's planned peak demand; (3) the diminished role of the existing CTs as a resource to provide retail energy in years of low hydro conditions; and (4) the ongoing need for PSE to address potential capacity shortfalls in extreme peak conditions.

The combination of load growth and limited hydroelectric energy indicates that the Company is moving from an energy-constrained system that has a major reliance on hydroelectricity to a capacity-constrained system. For example, in 1992, the capacity associated with the Mid Columbia hydro contracts accounted for approximately 38% of the Company's peak demand and that number has dropped to approximately 29% based upon the forecasted normal peak at 23°F. This percentage would be even less based upon extreme peak conditions, which is 16°F.

An indication that the Company is now capacity constrained is the reliance on peaking contracts, winter call options, and market purchases to meet system peaks.

Finally, the recent historic operation of the Company's CTs is indicative of their diminished role in providing a hydro firming function for retail load. The high effective heat rate of the CTs, on the order of 12,000 BTU/kWh, makes these units relatively expensive resources for meeting energy requirements and thus they are rarely operated except to meet extreme, short duration peaks.

Q. What is the basis for changing the fuel mix and fuel cost for the CT in the peak credit calculation?

A. The fuel cost issue was raised by ICNU in the 2004 general rate case. ICNU pointed out that natural gas costs at the time of system peaks is likely to cost more than the anticipated average annual cost of gas.[3] I completed an analysis to develop an indicative relationship between average annual gas cost and gas cost on low temperature days.

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[3] Exhibit No. 371 HC (DWS-1HCT page 33.

My selection of a cut-off temperature for "cold days" was based upon average daily temperatures versus the minimum temperature of the day. Since there were few very cold days, average temperatures at 23°F or lower, I chose the cut-off of an average daily temperature of 40°F to represent the cold days. This results in using approximately 5% of the days of the year. I compared the average gas price on theses cold days to the average price for the year over the last eleven years. The result of my analysis is that it is appropriate to use a 17% adjustment factor for the gas cost for the CT compared to the average annual gas cost used for the CCCT in the peak credit calculation.

I also excluded the use of fifty hours of oil operation in the peak credit calculation. The cost of operating those units using oil is not included in the proforma power costs. Therefore, elimination of the assumption of operating the CTs with oil is more consistent with current planning criteria and forward projection of power costs.

Q. What is the rationale for reducing the number of hours of assumed operation?

A. The reduction of the number hours of assumed CT operation from 200 to 75 hours per year is designed to better reflect the number of hours that the units would be required to operate to meet the system's peak demand. The basis for 200 hours is a historic Company planning criteria that is no longer used. The selection of the number of hours is further discussed later in my testimony when I review the

Company's proposed changes to the allocation of generation and transmission demand costs.

Q. What is the impact on the peak credit calculation associated with reducing the number of assumed operating hours of the CT?

A. Reducing the number of assumed hours of CT operation lowers the demand allocation as a result of including less fuel and variable O&M costs in the numerator of the peak credit ratio. For example, using 200 hours instead of 75 hours results in increasing the peak credit ratio from 20% to 22%.

D. <u>Classification of Transmission Costs</u>

Q. What is the history of the Commission Basis transmission cost classification?

A. In the Electric Rate Design Case the Company proposed to subdivide transmission cost into two functions: (1) transmission used to integrate generation; and (2) transmission within PSE's service territory used to deliver power to customers. These two functions were referred to as generation-related transmission and distribution-related transmission. The Company had proposed to classify the first category consistent with the generation methodology and classify the second category as 100% demand. However, the Commission rejected the proposal to classify distribution-related transmission as 100% demand based on its opinion that other considerations beyond peak demand influence the cost of the transmission system.

Q. Does the Company propose any changes to transmission cost classification in this case?

A. The Company believes that the historic classification of approximately 13% of the transmission system on demand is too low and is inconsistent with the national convention of classifying and recovering transmission costs on the basis of demand. Instead, the Company is proposing in this case to use the modified peak credit method, as described in the prior section of my testimony, to classify transmission costs. Under this proposal the classification of transmission demand cost increases from 13% to 20%.

Q. Is the distinction between generation-integration transmission and other transmission necessary?

A. Yes. Retail rate Schedules 448 and 449 as well as the large customer in the Firm Resale class are not using PSE's remote generation resources. Thus, it is appropriate to exclude them from the allocation of costs for transmission lines used for resource integration. At the same time, these classes should continue to receive an allocation of the portion of the transmission system used to deliver energy to and within PSE's system.

E. Allocation of Generation and Transmission Demand Costs

Q. What is the Commission Basis methodology for allocation of generation and transmission demand costs?

A. The currently approved methodology dates back to 1992 in the Electric Rate Design Case and is based upon each class's coincident contribution to the top 200 hours of system load in the test year. The rationale is based upon the Company's argument in that case that use of the top 200 hours was consistent with the design of the system peak facilities.

Q. Is the Company proposing to change the allocation methodology?

A. Yes. The Company no longer uses the top 200 hours for determination of peak generation requirements. The Company now uses peak demands at 23°F and 16°F to determine peak generation requirements. Therefore, planning for peak is a function of temperature and is no longer related to the top 200 hours of load in the year.

Q. What is the Company's proposed revised methodology?

A. To develop a new methodology consistent with the Company's current peak planning, I examined the number of hours in the last 10 years where the hourly temperature was 23°F or colder and determined that there were significantly less than 200 hours. The largest number of hours below 23°F in a year was 75 hours.

I also reviewed test year data to look at the relationship between peak loads and temperatures. While the data do not suggest a clear cut-off point, the top 75 hours have peaks that are within 90% of the system peak.

Thus, the Company is recommending continued use of a demand allocation factor tied to historical contribution to system coincident peaks. This approach is relatively easy to implement based upon PSE's load research programs. However, the Company proposes to reduce the number of peak hours used in the calculation from 200 to 75 hours. Use of fewer hours is more reflective of the current peak demand design criteria and the objective of the Commission Basis methodology.

Q. What is the impact of allocating demand costs on the top 75 hours of system demand versus the top 200 hours?

A. Based upon the test year demands, the change is minimal. For example, the residential allocation of demand costs changes from 58.7% to 58.5%. For general rate cases with colder test years, the change is likely to be more significant.

F. Distribution Cost Allocation

1. Distribution Substations and Feeder Costs

Q. Is the Company proposing to modify the methodology used to allocate distribution substations and feeder costs?

A. Yes. The proposed methodology assigns the cost of underground circuits, overhead circuits, and substations based upon allocation factors constructed from each class's contribution to the feeder's and substation's peak and the length of the distribution circuit. These allocation factors were constructed from monthly energy and load factors for the twelve-month period ending September 2005 and are a better indication of the costs incurred to serve each class of customer.

Q. How does this method differ from the approach approved by the Commission in the 1992 rate design case?

A. The difference is in the level of detail rather than a difference in philosophical approach. Consistent with its 2004 general rate case, the Company has taken advantage of its databases and allocated distribution costs at a circuit and substation level based upon non-coincident peak ("NCP") demands of each class using the substation and feeder. NCP demands are calculated as sum of the peak of each class regardless of when each class's peak occurs. For a simplified example, assume that there are only two rate classes on a distribution substation. If the residential peak demand on the substation was 10 MW and it occurred in

January and primary voltage peak demand on the same substation was 10 MW and it occurred in July, then the non-coincident peak would be 20 MW and each class would be assigned 50% of the cost of the substation. Note that the non-coincident peak will almost always be greater than the total peak that the substation actually experiences.

Q. Would you please describe specifically how substation costs were allocated?

A. Each Customer class's contribution to the Company's substation's peak was calculated using average hourly consumption of each class divided by NCP load factors. The resulting percentage was multiplied by the substation's net plant balance expressed in 2005 dollars to develop the substation cost allocations for FERC accounts 360-362.

Q. How were distribution line costs allocated?

A. The cost of the distribution feeder investment is a function of both load and line miles. The Company used its Customer and distribution feeder databases to associate each of its Customers with over 1,000 Company feeders. NCP load factors were used for each Customer class to determine each class's contribution to each feeder's non-coincident peak. Each class's contribution to peak was multiplied by the number of overhead and underground miles on the feeder. These allocators were then summed across all the feeders to develop the overhead and underground distribution line cost allocators. The overhead allocators were applied to FERC accounts 364 and 365 and the underground allocators were applied to FERC accounts 366 and 367.

Q. Why should miles of distribution line be incorporated into the cost allocation?

A. The cost of building overhead or underground distribution lines is primarily a function of distance, with cost adjustments for capacity. Cost is driven by the number of miles of trench excavated, miles of conductor required, number of poles installed, etc. There is an incremental cost for load, but it is relatively small since the Company uses only a few standard wire sizes for overhead and underground feeders and taps.

2. <u>Distribution Line Transformer Costs</u>

Q. Please describe the Commission Basis method for classifying distribution line transformer costs.

A. In the 1992 rate design case, the Commission adopted the "Basic Customer method" which stated that the Customer Charge should recover the costs associated with each customer. At that time, the Commission determined that only the service line, meter, meter reading costs and billing related costs were customer related costs.

Q. Please describe the Company's proposal for allocating line transformer costs.

A. The Company is proposing that line transformers also be classified as a customer cost. Line transformers are installed specifically to serve a particular customer or group of customers. Once installed, the transformer represents a fixed cost of providing service to the customer or group of customers. For example, in the typical residential subdivision developments being constructed today, the Company installs a 37.5 kVA pad mounted transformer for every twelve homes.

Q. Are the transformer costs the same for each customer?

A. No, there are variations due to density of customers and for large load customers the transformer is sized for the anticipated load. However, once a transformer is placed in service, it is normally there for the life of the transformer and customer demands are relatively stable. If a customer reduces their electric load, the Company normally does not change a transformer since the cost to remove and replace a transformer generally outweighs the cost of having an oversized transformer in the field. Furthermore, the Company uses standard transformer sizes in order to reduce ordering, inventory and record keeping costs.

In summary, because transformer sizes are standardized, transformers are designed to serve a particular customer or group of customers, and transformers are rarely changed over their lifetime, transformer costs are appropriately characterized as customer related costs as opposed to demand related costs.

Q. Is there a one-to-one relationship between a customer and a transformer or a rate class and a transformer?

A. No, there is not a one-to-one relationship. The cost of service analysis shows that there are 242,680 line transformers that PSE uses to serve approximately one million customers at secondary voltage levels. Approximately 82% of the transformers are used to serve one class only. Approximately 12% of the transformers are used exclusively for non-residential customers. Of the remaining transformers that are shared between residential and non-residential customers, approximately 47% of those shared transformers are for residential customers that share the transformer with another meter that qualifies for the residential exchange rate. This translates into 89% of the residential customers being served by transformers used exclusively for residential service or service that qualifies for the residential and farm exchange credit.

Q. Can a piece of utility equipment that serves multiple customers be classified as customer related?

A. Yes. The billing system and meter reading system serve multiple customers but these are considered customer costs. The test is not whether the cost is dedicated to a single customer or a group of customers but whether the cost is best characterized as varying with the number of customer, the customers' demands or the customers' usage.

Q. Can a piece of equipment that is sized for demand be classified as a customer cost?

A. Yes, for example meters are classified as a customer cost but the meter installed, and accordingly its cost, is based upon the customer's anticipated load.

Q. Would you please describe how the line transformer cost allocation factor was developed?

A. The Company used its customer database to associate each line transformer with the customers using the transformer. This resulted in allocating approximately 243,000 transformers to the different classes by type and size. Approximately 82% of the line transformers are used by a single class and thus were directly assigned. The remaining transformers were assigned to each class based upon the class's relative contribution to the transformer's load. The transformers were priced at current costs, including installation, to determine each class's contribution to embedded line transformer costs (FERC account 368).

Q. How are service lines allocated in the Company's cost study?

A. Service lines are allocated based on the number of customers taking service at secondary voltage. All underground services are allocated to the residential class since non-residential secondary voltage customers own their own services. Overhead services are allocated based on the number of secondary voltage overhead service customers in each class. These allocations are not the same as the Commission Basis methodology, but the Company has used its newer methodology in its past two general rate cases without controversy.

G. **<u>Administrative and General Costs and Other Cost Allocation Factors</u>**

Q. How are Administrative and General costs allocated?

A. The majority of Administrative and General costs are assigned on adjusted production, transmission, distribution, and customer costs. Property insurance was allocated on plant, and pensions and employee insurance follow the allocation of salary and wages.

Q. What other direct cost allocators are used in the cost of service study?

A. The Company reviewed historical experience with late payment and assigned the costs to each class. Other miscellaneous revenues associated with non-sufficient fund checks and reconnects are allocated to each class based upon a historical analysis of revenues received.

Q. What exhibit contains the Company's electric cost of service study?

A. The Company's proposed electric cost of service study is provided as Exhibit No. ____ (JAH-4).

Q. Did you prepare a cost of service study in accordance with the Commission Basis methodology?

A. Yes, this is provided as Exhibit No. ____ (JAH-5).

III. RATE SPREAD PROPOSAL

Q. Would you briefly describe rate spread and its relationship to cost of service?

A. Rate spread is the process of determining what portion of the total revenue requirement should be allocated to each customer class for recovery in that class's rates. Rate spread is guided by the results of the cost of service study. Cost of service provides guidance in structuring rates by identifying the customer, demand, and energy components of the revenue requirement.

Q. What rate spread policy factors did the Company consider in developing its electric rate spread recommendation?

A. The Company's proposal emphasizes two factors: customer impacts and the customer class relationship to parity. The Company's proposal is influenced by the results of the cost of service study. The Company continues to advocate movement towards parity, but is also concerned about the relative impact on different classes of customers.

With regards to Rate Schedules 26 and 31, the Company has been trying to achieve a cost-based difference between these schedules for a number of years. A cost-based rates differential will allow Customers to choose the delivery voltage that best fits their service needs rather than preferring one service to another because customers on Schedule 26 pay relatively more on a percent of parity basis while customers on Schedule 31 pay less than parity. While this target has not been achieved yet, the Company proposes to move closer to the target in this case by assigning the Schedule 31 class 110% of the average rate increase and Schedule 26 slightly less than the average such that both classes together receive the average rate increase.

Q. Would you please summarize the Company's proposed rate spread?

A. Based upon the parity ratios shown in the Company's cost of service study and the principle of gradualism, the Company proposes to apply the average rate increase to classes within 5% of parity with the exception of Schedule 40 and the treatment of Schedules 26 and 31 described above.

The Company proposes to increase the rates on Schedule 40 based upon the tariff design developed in the 2004 general rate case. This translates to adjusting the production and delivery component of the rate increase so that on a loss-adjusted basis it is equivalent to the high voltage rate at parity. Changes in the customer-specific distribution cost recovery reflect changes in the weighted cost of capital and the operations and maintenance as well as administrative and general cost multipliers.

The retail wheeling class and firm sales for resale class are more than five percent above parity. The Company proposes to assign half the average rate increase to the retail wheeling class and no increase to the wholesale for retail class. No adjustment to the later class is appropriate since they are paying above their cost of service and the Company does not have the potential to recover additional costs assigned to that class of customers since an application to the FERC to raise those rates must be cost-based.

Finally, the rate increase assigned to the substation transformer capacity rentals rates (Schedule 62) is determined per Attachment C – Rate Methodology that is part of the filed rate.

A summary of the proposed rate spread proposal follows and the detailed worksheet is Exhibit No.___ (JAH-6).

Customer Class	**Rate Schedule**	**Parity Ratio**	**Proposed Rate Increase**
Residential	7	99%	8.89%
General Service, < 51 kW	24	100%	8.89%
General Service, 51 - 350 kW	25	105%	8.89%
General Service, >350 kW	26	103%	8.31%
Primary Service	31 / 35	97%	9.78%
Campus Rate	40	100%	1.82%
All Electric Schools	43	97%	8.89%
High Voltage	46 / 49	103%	8.89%
Lighting Service	51 - 59	99%	8.89%
High Voltage – Retail Wheel	448 / 449	111%	4.40%
Firm Resale	5	130%	0%
System Total / Average		100%	8.72%

IV. ELECTRIC RATE DESIGN

Q. What are the Company's rate design objectives in this case?

A. Rate design inevitably involves balancing competing objectives. The Company has multiple objectives: (1) where practical, maintain rates that are relatively simple for the customer to understand; (2) maintain relationships between rate design and cost of service for cost-based rates; (3) avoid rate shock; and (4) promote revenue recovery stability for the Company.

Q. Are the Company's rate design objectives consistent with general rate design principles?

A. Yes. As noted in the "Principles of Public Utility Rates," by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, 2nd Edition, 1988, rate spread and rate designs should consider the following objectives: (1) Rates must be effective in yielding the total revenue requirement; (2) Rates must provide revenue stability and predictability to the utility and the customer; (3) Rates must promote justified usage; (4) Rates must reflect cost of service; (5) Rates must be designed fairly so there is smooth transitions between usage levels, etc.; (6) Rates must not be unduly discriminatory; (7) Rates must promote efficiency; (8) Rates must promote simplicity, certainty, understandability, and acceptability; and (9) Rates should not be prone to misinterpretation.

Q. Please summarize the changes the Company proposes to make to rate design.

A. The Company's rate design changes include:

- Increasing the customer charges in order to recover more nonvariable costs on a fixed charge basis. Specifically, the Company seeks approval of recovering part of the transformer costs in the customer charge;
- Linking the rate design of Schedules 26 and 31 as part of the Company's effort to combine the two rates for the large load customers and offer a cost-based differential for customers selecting primary voltage transformation services;
- Modifying the language in Schedule 40 to clarify how to address new system load on the campus rate;
- Addition of an experimental residential Critical Peak Pricing rate and modification of the current Voluntary Load Curtailment Rider (Schedule 93) to implement the demand side management program described by Mr. Calvin Shirley, Exhibit No. __(CES-1T).

I review each of these changes below and summarize how the rate increase was applied to the current rate structures.

Q. Has the Company prepared new tariff schedules based upon the cost of service study results and consistent with its rate design proposals in this case?

A. Yes, the proposed tariff schedules are presented in Exhibit No.___ (JAH-9).

A. <u>Increasing the Basic Charges to Better Recover Fixed Costs</u>

Q. Why is the Company seeking to recover more of its costs through the basic charges?

A. PSE's current electric rate schedules rely heavily on volumetric rates to recover fixed delivery costs. That is, if customers pay only the basic charge to PSE, PSE will not recover the costs required just to have the customers hooked up to its electric grid. Instead, a portion of such fixed costs are recovered in the portion of the customers' bill that varies depending on how much electricity the customers use.

In order to recover the revenue requirement that is assigned to the rate schedules of each customer class in a rate case, PSE's customers must use at least as much electricity as they were projected to use during the rate year at the time rates were set. However, the electricity usage of PSE's residential customers has been dropping approximately 0.7% per year due to a number of factors including conservation, fuel switching, and changes in the housing mix in PSE's service territory. Because of this declining use per customer, PSE is under recovering the nonvariable costs of providing service to its electric customers.

Q. Will the increased customer charges help address the issue of under-recovery of cost due to declining usage per customer?

A. The proposed increased basic charges will not solve the problem because they are only a partial step toward recovering PSE's fixed costs through the basic charges. However, the increases represent a gradual movement towards recovering fixed costs via non-volumetric rates.

Q. Would you please summarize the Company's proposal to increase the basic charge rate component?

A. In the Commission Basis Electric Rate Design case, the cost basis for the basic charge was derived from the meter costs, billing costs, and service line costs. The Company is proposing in this case to include approximately 55% of the line transformer cost as well.

Q. What would the impact be for residential customers?

A. The Basic Charge on residential schedules would increase $1.00, from $5.75 to $6.75. Because there are corresponding reductions in the volumetric portion of the rate schedules the Company is proposing, approximately half the residential bills would change by less than $0.50 per month as a result of increasing the basic charge by one dollar per month. A one dollar Basic Charge increase would produce higher percentage increases for low users of electricity, and yet their total bill increase in dollar terms would not be that significant. Less than 14% of the residential bills would experience an additional increase of more than 5% as a result of increasing the Basic Charge by one dollar. These fourteen percent of bills correspond to monthly consumption of less than 150 kWh per month.

Q. How does PSE's proposed residential basic charge compare with basic charges of other utilities?

A. Of 26 Washington utilities I reviewed, 17 of those utilities have higher basic charges for electric service than PSE's proposed basic charge of $6.75. On a nationwide basis, of the 74 utilities surveyed, 49% (36 utilities) have higher basic charges than $6.75. These comparisons are shown in Exhibit No. ___(JAH-7).

B. Summary of Residential Rate Design

Q. Please summarize the Company's proposed residential rate design.

A. The current rate is a two-block energy rate with a monthly basic charge of $5.75. The Company proposes to increase the basic charge rate $1.00 for both single phase and three phase service. The remainder of the increase was applied on an equal percentage basis to each block in order to maintain the current differential.

I do not propose increasing the block differential for a number of reasons. First, increasing the differential will tend to increase the financial burden on electric space heating customers who likely have limited alternative cost-effective heating options. Second, increasing the differential results unfairly shifts costs from the

36% of the bills that have consumption below 600 kWh / month to the remaining residential customers. Finally, an increased differential could adversely impact revenue recovery stability as a result of continued customer conservation and fuel switching and the lost revenue exceeding the power cost savings to the Company.

For rate stability purposes I am not proposing to change the blocking of the residential rate. However, I note that the block design no longer has any relationship to the allocation of relatively low cost hydroelectric energy. I have calculated that the residential customer's monthly share of hydroelectric energy is less than 300 kWh per month.

C. Summary of General Service Rate Design

Q. Please summarize the proposed small general service rate design.

A. The General Service (Rate Schedule 24) class is not demand metered and has a single block seasonal rate. The Company's proposal is to increase the basic charge rate $1.00 for both single phase and three phase service. The remainder of the increase is applied to the summer and winter energy rates so as retain the current seasonal differential.

Q. Please summarize the proposed medium general service rate design.

A. The Small Demand General Service (Rate Schedule 25) class has a two block seasonal energy and demand rate. The first block has no demand charge and the demand component is recovered in the first block of the energy rate. The basic charge is increased by $1.00. The second block of the demand charge was adjusted to reflect the demand component of the cost of service subject to the constraint that the increase in the demand rate is no more than 125% of the average schedule increase. I then increased the second block energy rate so that the combined increase in the energy and demand rates equal the average rate increase. This protects the largest volume users on the schedule from absorbing more of the rate increase as a result of increasing the demand rate more than the average increase. The balance of the revenue requirement was applied to the first block seasonal energy rates in a manner that maintains the current season differential.

D. <u>Summary of Large General Service Rate Design: Schedules 26 and 31</u>

Q. Please summarize the proposed large general service rate design.

A. There are two rates in this group: Large Secondary (Rate Schedule 26) and Primary General Service (Rate Schedule 31). The Company's proposal is to link the two rates such that the lower rate for Schedule 31 reflects both the cost savings to the Company for not providing primary voltage transformation service and a discount since for Schedule 31 energy and demand since the customer pays for the transformer losses (assuming that the meter is located on the high side of the line transformer).

Q. Why is the Company making this proposal?

A. For a number of years, the Company has been moving these two rate schedules towards comparable rates on the theory that the rates should be comparable since the loads and load factors are comparable. The Schedule 31 rate differences should reflect the savings to the Company for not providing the transformer and the discount to the customer associated with the customer responsibility for transformer losses when delivery is metered at primary voltage.

The drive towards a cost-based differential between the two rates is to create an end-point where customer motivation to take primary service will be based upon customer needs rather than a desire to qualify for the schedule with the lowest rate. Therefore, in order to achieve this objective, the Company is proposing to start to tie the two rate designs together by linking the demand rates but not the energy rates.

Q. Did you test the theory that the loads and load factors are comparable in preparing this case?

A. Yes. I reviewed the Schedule 31 rate class and concluded that in aggregate, the load characteristics of these customers are similar to Schedule 26. Customers with demands greater than 350 kW constitute 52% of the customers and 93% of the load. In comparison, Schedule 26 customers have peak loads over 350 kW as a condition of qualifying for service under the Schedule. The two rate classes have similar coincident peak load factors as used for determining cost allocations in the cost of service study (the ratio of the average annual load to the average top 75 hours of load coincident with the system peak). The coincident peak load factor for Schedule 26 is 88.6% versus 87.4% for Schedule 31. I also examined the non-coincident peak factors of the two schedules. (The non-coincident peak factors are used to allocate distribution costs.) The results of the analysis are that on an absolute value basis, the monthly non-coincident peak load factors differ by 0.2% to 3.5%. These results support the Company's proposal.

Q. Why is the Company maintaining separate rate schedules for Schedules 26 and 31 if the rates are linked?

A. The different rates are maintained for three reasons. First, the energy rates are allowed to diverge in order to continue to move towards a single rate while mitigating the impacts of a single loss-adjusted rate. Second, there are provisions in Schedule 31 that require some customers to take primary service. These provisions provide protection to the remaining customers by not requiring the Company to install expensive special purpose distribution lines that serve a single customer. Third, as previously noted, there are two major types of customers on Schedule 31: 48% of the customers account for 7% of the class energy consumption. The Company will continue to look at the best way to cost effectively serve this subgroup of customers, which may include proposing a separate rate class for the small load primary voltage customers.

Q. Please summarize the proposed Schedule 26 and Schedule 31 rate design.

A. The demand charges for Schedule 31 were set based on the cost of service study subject to the constraint that the increase in the demand charges is no more than 125% of the average increase to the class. The Schedule 26 demand charges were then set equal to the Schedule 31 demand charges on a loss adjusted basis and the addition of half of the line transformer cost. The result of this rate design is that the Schedule 26 demand charges are close to the demand cost in the cost of service study.

The Schedule 31 and 26 energy rates were then calculated to spread the remaining rate increase after applying an average increase to the kVARH charges. The result is that the Schedule 26 energy rate is still higher than the Schedule 31 energy rate on a loss-adjusted basis.

E. Campus Rates: Schedule 40

Q. Please describe the purpose of Schedule 40.

A. This rate was developed in the 2004 general rate case in response to customers with large loads, greater than 3 MW, that are either typically in a campus configuration, or share a distribution feeder with other customers. The rate first became effective on March 17, 2005 and is voluntary until the general rate case following the third year anniversary of that date. Additional customers who qualify for this rate cannot obtain a customer-specific distribution rate between rate cases. There are two additional customers who qualify for this rate and have expressed an interest in service under Schedule 40. These customers have been included in Schedule 40 for the purposes of the proforma and proposed rate design.

Q. Please summarize the Schedule 40 Rate Design.

A. Schedule 40 has customer-specific distribution rates and a bundled energy and transmission rate that reflects Schedule 49 after an adjustment for losses and parity. The distribution rate is designed to recover customer specific distribution costs on a levelized basis. The bundled production and transmission energy and demand rates are linked to the parity-adjusted high voltage rates since the total aggregated load of each of these customers is comparable to high voltage customers.

The Company reviewed the distribution rates of the three customers on the rate and determined that no adjustment to the assigned distribution line cost allocation is appropriate as there was no rate-based distribution plant added or retired. However, one customer had an adjustment to the substation cost assignment based upon plant additions and retirements occurring since the last rate case. In addition, the Company identified two more customers who qualify for the rate and has developed distribution rates for those customers. A proforma adjustment for the two additional customers have been made after a preliminary determination that those customer wish to elect Schedule 40.

I examined the relationship between the loss adjusted Schedule 49 energy and demand rates and the current Schedule 40 rates and determined that applying the new loss adjusted Schedule 49 rates would not result in an increase. In order to allocate a share of the power cost increase to Schedule 40, the Company proposes applying half the Schedule 49 increase to the current Schedule 40 power cost / transmission rate component.

The Company is also proposing to modify the qualification language to clarify the treatment of new load on the system from Schedule 40 customers. The change will allow incremental load to the PSE system on existing feeders to be included in the customer's campus rate to be allowed on the rate in between rate cases.

F. Summary of High Voltage Rate Design

Q. Please summarize the high voltage rate design.

A. The demand charge for the full requirements non-interruptible high voltage customers (Schedule 49) was based upon the cost of service study subject to the constraint that the demand charge increase does not exceed 125% of the average rate increase. The percentage adjustment in the Schedule 49 demand charge was applied to the Schedule 46 (interruptible high voltage service). The remainder of the increase was spread to the Schedule 46 / 49 energy rates. The energy rates are maintained for both schedules.

The rate increase assigned to the Power Supplier Choice and Retail Wheeling (Rate Schedules 448, 449 and 459) was done in a two-step process. The first step was to calculate any change in the basic charge. The second step was to take the remaining increase to be allocated and calculate that increase on a $ / kVA basis. This approach was used, rather than an equal percentage approach to avoid creating further disparities in the parity rations between the primary and high voltage rates.

G. Rate Design for PSE's New Demand Side Management Program

Q. Please describe the rate design for the experimental critical peak demand side management program described in Mr. Shirley's testimony.

A. The rate design set forth in a new Schedule 102 is based upon the objectives of the experimental rate outlined by Mr. Shirley. The critical peak pricing was based upon considering a range of values. The value of $0.40 / kWh for the 80 hours of critical peak reflects a combination of different perspectives on the cost of capacity, the cost avoided should a customer reduce or shift load in the critical peak period, and what might have appeal to the customer. The rate was designed to be revenue neutral for an average customer, assuming no change in behavior.

The rate design reflects the treatment of the lower first block rate that was in the Company's former Time of Day Residential Service rate. In order to provide customers with equivalent rates assuming no change in usage, the rate is designed around the approved residential tail block rate and a credit is provided for the first 600 kWh of usage. The low volume credit will reflect the Commission approved differential between the first and second block of the standard residential rate.

H. Rate Design for PSE's Depreciation Tracker Proposal

Q. Have you prepared a tariff sheet to implement PSE's Depreciation Tracker Proposal?

A. Yes, Schedule 124 is filed with an effective date of January 1, 2007. The methodology used to calculate the rate is provided in Exhibit No.___(JAH-8).

Q. Please describe the rate design associated with the Depreciation Tracker.

A. Adjustments for distribution depreciation costs will be allocated to each class, with the exception of Schedule 40, according to the allocation of those costs as determined in the most recent PSE general rate case. The transmission and distribution allocation factors are calculated in the cost of service model. The specific percentages will be based upon the compliance model filed following the Commission's decision on the rate case. The costs allocated to each class will then be recovered on a class-specific energy charge adjustment calculated by dividing the sum of the allocated transmission and distribution depreciation cost adjustment by the forecasted load of the class.

Q. Why is Schedule 40 removed from the Depreciation Tracker?

A. The distribution charges bundled in the rates for Schedule 40 customers are customer specific based upon a levelized distribution cost, including depreciation expense, at the time the customer goes on the rate. The rate is then adjusted for new plant additions and retirements in subsequent rate cases. Separately tracking the incremental customer-specific depreciation costs between rate cases and adjusting the tracker rate introduces a complexity that does not appear to be warranted.

I. <u>Additional Rate Schedule Comments</u>

Q. Is the Company filing a revised Schedule 95 with this rate case?

A. No. The cost of service and rate spread presented in my direct testimony reflects the current projections of rate year power costs with proforma revenues based upon the Schedule 95 rates that became effective on November 1, 2005, pursuant to the Commission's order in PSE's 2005 PCORC case, Docket No. UE-050870. The Company's rate design in this general rate case assumes that Schedule 95 will be set to zero at the time the new rates approved in this case go into effect. However, a revised Schedule 95 with a "zero" rate is not being filed in conjunction with this general rate case in order to avoid suspending the rate at this time. This will reduce complications associated with the scheduled filing of a revised Schedule 95 with a new rate and an effective date of July 1, 2006, pursuant to the 2005 PCORC order.

Q. Will the filing of a revised Schedule 95 during the course of this rate case have any impact on the case?

A. Once the new Schedule 95 rate is approved, the Company will file an updated cost-of-service study to reflect any resulting changes in power costs and the new proforma revenues. This may result in changes in parity ratios and a revised rate spread proposal that will be consistent with the methodology I have outlined in my testimony. Finally, new rates will be developed based upon the power costs that are updated pursuant to the 2005 PCORC, with Schedule 95 being set to zero.

Q. Is the Company proposing any changes to Schedule 194, the Residential and Farm Energy Exchange Benefit rate schedule?

A. No, not within this filing. Schedule 194 is the vehicle by which the Company passes through to residential and small farm customers the Residential Exchange Program benefits received from Bonneville Power Administration. The current Schedule 194 provides for credits through September 30, 2006. Under the applicable agreements with Bonneville Power Administration, the method of determining the benefits to be paid by BPA is to change as of October 1, 2006. A revised Schedule 194 will be filed such that a new level of credit can take effect October 1, 2006.

Q. Why is the Company proposing to cancel Schedule 119, the Capital Structure Tracker Rate Adjustment?

A. This is a housekeeping matter to cancel the capital structure penalty mechanism that was added to the Company's tariff schedules as part of the settlement of PSE's 2001 general rate case, Docket Nos. UE-011570 et al., two rate cases ago.

V. TEMPERATURE ADJUSTMENT

Q. Does the Company's electric cost of service and rate design implement the Company's proposed electric weather normalization methodology, as described by Dr. Jeffrey Dubin?

A. Yes. The cost of service reflects the temperature adjusted power costs and the rate design reflects the proforma adjustment of energy sales to reflect that the test year was warmer than normal. Based upon the implementation of the Company's proposed weather normalization methodology, 82% of the kWH weather adjustment was applied to the residential class.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

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