EXHIBIT NO. _____ (JAH-1T)
DOCKET NO. UE-04____/UG-04____
2004 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-04____** **Docket No. UG-04____**

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

APRIL 5, 2004

PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

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

A. My name is James A. Heidell and I am a Managing Consultant with PA Consulting Group. My business address is PA Consulting Group, Inc., 390 Interlocken Crescent, Suite 410, Broomfield, CO 80021.

Q. Please summarize your educational background and professional experience.

A. I have a BSE in Civil Engineering from Tufts University, a MS in Engineering Economics from Stanford University, and an MBA concentrating in Finance from the University of Washington. I am a Chartered Financial Analyst (CFA). I have over twenty years of experience in the energy industry. I started as an engineer / consultant at Battelle Pacific Northwest Laboratories and subsequently at Synergic Resources Corporation. From 1990 to 2000 I worked at Puget Sound Power & Light Co. and then Puget Sound Energy, Inc. ("PSE" or "the Company") in a number of positions including Manager of Pricing, Director of Federal and State Regulation, and Director of Financial Planning. In September 2000 I joined PA Consulting Group where I concentrate on the financial analysis of energy markets and power projects for a variety of clients including retail and wholesale energy companies, investment banks, and venture funds. My qualifications are presented

in Exhibit No.___ (JAH-2).

Q: Please summarize the scope of your testimony.

A: My testimony contains six sections related to development of the electric and natural gas rate proposals Ms. Paulson addresses electric and natural gas cost of service issues.

With regards to electricity and natural gas pricing, I first describe the conditions that drive the proposed rate designs. Second, I present the electric weather normalization procedures utilized in Ms. Paulson's cost of service study. Third, I present the Company's electric rate spread proposal to translate cost of service results into class revenue requirements. Fourth, I present the Company's electric rate design and proposed tariffs. Fifth, I present the Company's natural gas rate spread proposal and finally the associated rate design and tariffs.

II. RATE SPREAD & RATE DESIGN OBJECTIVES

Q. What are the Company's objectives with regard to the electric and natural gas rate spread and changes in the rate design?

A. Rate spread and rate design involves balancing often competing objectives including: 1) having customers pay their fair share of costs as guided by cost of service; 2) reducing cross subsidization between different customer classes; 3) providing the Company with a reasonable opportunity to recover its revenue requirement; and 4) mitigating rate shock. The Company has proposed a number

of changes to its cost of service methodology, rate spread, and rate design as part of its ongoing efforts to balance these objectives.

Q. Is the Company proposing to redesign residential rates?

A. Yes. PSE, like most utilities, relies on volumetric charges to recover a large amount of fixed costs. As long as consumption is relatively stable, the volumetric cost recovery mechanism is adequate. However, this mechanism does not always work. Short run changes in usage are not offset by corresponding changes in nonvariable costs associated with maintaining, operating, and recovering capital costs associated with a large delivery infrastructure. An example widely seen in the natural gas delivery business is the use of weather normalization adjustments in recognition that the utility must recover large fixed costs over an extremely weather sensitive load. In the case of PSE, the Company has experienced, and is forecasted to continue to experience, a long-term trend in declining usage per customer in both gas and electric consumption. While this decline can be ascribed to a number of different causes, the end-result is the same: reduction in load creates a compounding under-recovery of delivery costs until the next rate case.

The Company has three complementary proposals for addressing this issue. The first proposal is to gradually recover more nonvariable costs on a fixed charge basis. The second proposal is to reduce the inversion in the residential electric blocks to reduce the impact on revenues due to reduced usage per customer. The final proposal is to have an annual rate adjustment to offset the declining usage.

Q. What is your perspective on cross subsidization in PSE's rates?

A. There are multiple sources of cross subsidization and I recognize that the degree of cross subsidization depends on one's perspective on appropriate cost allocation methodologies. Inter-class cross subsidization is a function of the cost allocation study, and there are competing perspectives on what methodologies are appropriate. Furthermore, there are non-cost of service considerations that are reflected in the class revenue allocations.

A significant question is how much of the costs to serve each class are being recovered in revenues collected from that class (parity). On balance, I do not see many parity issues that have to be addressed in this case. However, one electric parity issue that I recommend the Commission continue to address is the difference between large secondary and primary voltage customers. The second type of cross subsidization I recommend addressing is intra-class cross subsidies. These tend to be difficult to correct due to the desire to mitigate bill impacts to customers that are compounded by general rate increases. There continue to be intra-class parity issues due to the historical practice of recovering nonvariable costs through volumetric charges. This results in low energy use customers within a rate class often being cross subsidized by the larger volume users. This issue is partially addressed by the rate design modifications incorporating higher fixed charges. Finally, there can be cross subsidies between old and new customers if new customers do not bear the full incremental cost of connecting to the electric grid. This last issue is typically addressed in line extensions. The Company has

not proposed any changes to its line extension schedules in this filing.

In the current study, the class parity ratios are impacted by what the Company believes are appropriate and necessary changes in cost allocation. As a result, the Company's proposal for class revenue assignment is guided directional by the studies presented by Ms. Paulson. The rate spread and rate proposals that I have endorsed are designed to take a step toward reducing these cross subsidies and providing customers with appropriate price signals.

Q. Does the Company's electric cost of service address weather normalization of demand and energy?

A. Yes, the Company has developed a new methodology for weather normalizing class peak demands and monthly energy consumption. I briefly review the methodology later in my testimony. The Company is committed to reviewing the proposed methodology in a collaborative approach as proposed in the recent Power Cost Only Rate Case, Docket No. UE-031725. Given that there are a number of statistical approaches that have different strengths and weaknesses and varying level of complexity, the Company recognizes that this topic is well suited for review in a collaborative process and will address these issues further with interested parties.

III. ELECTRIC WEATHER NORMALIZATION OF BILLING DETERMINANTS

Q: Why did the Company change its method for weather normalization of class

loads and sales?

A: Historically the Company did not weather normalize the top 200 hours of system peak demands for the purpose of identifying each class' contribution to the weather normalized peak. This process was undertaken to develop a fair cost allocation of capacity related production costs and transmission costs. The class level weather normalization energy adjustment was traditionally allocated to the residential and small commercial customer group. The Company reexamined this practice to update its view on the weather sensitivity of other rate class loads.

Q. What is the role of billing determinants in preparation of the cost of service study?

A. Billing determinants are used to allocate power production and bulk transmission related costs. These costs account for approximately two-thirds of the costs allocated in the cost of service study. Power costs are classified as either energy or demand. These two components are respectively allocated to each class based upon the class' contribution to total system energy use and coincident peak demand. Power production costs in this case are based upon energy requirements for the rate year (proforma to the test year by the production factor) assuming normal temperature and an average historic hydro condition. When the weather in the test year is either warmer or colder than normal there is a mismatch between the proforma energy and the determinants used to allocate production costs. There is also a mismatch when the customer mix differs significantly between the

test and rate year. Temperature adjustments are used to proform test year sales to reflect normal weather, and an adjustment was made to remove large power customers who will be securing their own power. The result is that the energy allocations are consistent with the normalized power costs for the rate year.

Q. Would you briefly describe how the weather sensitive energy adjustments were made?

A. The adjustments were made in a three-step process. The first step was to develop linear regression equations to characterize the relationship between temperature and load for each customer class. The coefficients of those equations were permitted to vary by month as well as by class. The data source for this step was made up of daily energy readings from the Company's Automated Meter Reading (AMR) database. The second step was to simulate daily customer loads over 31 years using the historical heating and cooling degree days and determine the average monthly load for each customer class. The third step was to weight the sample up to the population, adjust for losses and normalize the class loads to net weather-normalized GPI load developed by PSE's Power Planning.

Q. How was the class-level energy normalization analysis reconciled to the temperature normalized GPI for purposes of calculating the revenue adjustment related to weather effects?

A. In order to calculate the revenue impacts of the monthly GPI weather adjustment, the total of the temperature adjustments at the customer class level was compared

to the GPI temperature adjustment adjusted for losses. The differences between the total of temperature adjusted energy by class and the temperature adjusted GPI were proportionately allocated to the customer classes for each month, resulting in a weather adjustment at the customer class level that reconciles to the temperature normalized GPI adjusted for losses. Monthly rates for each customer class were applied to calculate the revenue attributed to weather effects.

Q. How were the monthly adjustments used to calculate the total class contribution to system sales?

A. The normalized temperature adjusted energy consumption was added back to the proforma class loads to develop the energy allocation factor and was also used for the billing determinants for the proforma revenue. The monthly weather adjustments to the residential billing determinants were applied to the tail block.

Q. What was the result of the energy normalization analysis?

A. The residential class is assigned 95% of the total energy adjustment. However, the overall adjustment covers up the complexity of the analysis. As a result of the test year having fewer heating degree days than normal but more cooling degree days, not only are the residential loads normalized upward in the winter, but also the non-residential loads are adjusted downward in the summer. A graphic of the results is shown in Exhibit No.___ (JAH-3).

Q. How was each class' contribution to the system's 200 peak hours calculated?

A. The Company analyzed hourly load data from a statistical sample of customers. These data were used to calculate each class' contribution to the peak both prior to and after the weather normalization analysis. The sample data were hourly readings from load research and other interval meters for the test year for all classes except 5, 29 and 43, for which data from older studies were used. Exploratory data analysis and statistical analysis were used to determine an optimal set of cut-offs (for use in identifying heating and cooling degree days) and an optimal disaggregation into four periods (summer / winter peak and summer / winter off-peak); optimal in the sense of permitting the best model of heating and cooling sensitivity of peak loads. Thus, we identified cut-offs to use in identifying heating and cooling degree days based on the revealed relationships between temperature and load rather than from a fundamental analysis of the thermodynamics of the specific building types.

The definitions of summer and winter seasons, and peak and off-peak hours, were statistically developed for each rate class, and temperature was modeled by a linear function of heating and cooling degrees with autocorrelated errors. This approach is preferred for properly constructing the error term of the regression equation**.** Hourly temperatures for the past 31 years were used to forecast hourly loads. In order to determine the 200 peak hours, the Company did not simply average each hour over the 31 years. This process would have resulted in incorrectly smoothing out the peaks. Instead, the Company identified the highest simulated load in each of the 31 years and identified the median value. Each

class' load for that median value was then selected for the peak hour. The process was then repeated for the second highest load hour, third highest load hour, and so on down to the 200th. A similar process was used to identify the 12 monthly coincident peaks and the 12 monthly non-coincident peaks.

Q. Please summarize the results of the analysis.

A. Prior to the loss adjustment, the average system demand for the top 200 hours was 3,221 MW. The temperature normalization increased the average to 3,440 MW. With regard to the cost allocation study, the absolute numbers are not critical; rather the relative contribution of each class to the peak is what drives cost assignment. The 200 peak hour normalization results in increasing the residential share of the component of power cost allocated on demand (13%) from 58.3% to 58.67%.

IV. ELECTRIC RATE SPREAD

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

A. Rate spread is the process of developing each class' share of the total revenue requirement. The process typically relies in significant part on the results of the cost of service study. Cost of service also provides guidance in structuring rates by identifying the customer, demand, and energy components of the revenue requirement. Rate spread is critical since this allocates the revenue requirement deficiency between the customer classes.

Although cost of service is the mechanism for identifying the allocation of costs to each customer class, the Commission has indicated that the results of cost of service should not be mechanically applied. Rate spread is the process by which cost of service results are combined with policy considerations to develop class-specific revenue requirements.

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

A. The Company considered two major factors: previously defined targets and customer bill impacts. In UE-920499, the Company proposed a target of moving customers to parity after three general rate cases. (Moving one-third of the way in the initial case and one-half of the remaining difference in the second case.) It is the Company's position that this target is still appropriate since removal of cross subsidies is an important factor in promoting appropriate choices by customers regarding their energy use. At the same time, the Company, like the Commission, rejected a mechanistic application of cost of service without consideration of rate impacts.

Another target to consider is the Rate Spread Collaborative parties' agreement in the 2001 general rate case to four annual adjustments to Rate Schedules 26 and 31 to move the rates in those schedules toward a cost-based difference. The goal was to establish a cost based rates differential so that customers are free to choose the delivery voltage that best fits their service needs rather than preferring one service to another because customers on one schedule pay more than parity while

the customers on other schedules pay less than parity. While this target has not been achieved yet, the Company is proposing to move closer to the target in this case by giving the Rate Schedule 31 customers the average rate increase and giving Rate Schedule 26 customers a smaller rate increase.

Q. What options did the Company consider in developing its electric rate spread recommendations?

A. The Company considered three options. The first option was to move each class to parity if they are paying below parity with the remainder of the rate increase spread equally among the classes. The second option was to move each class half way to parity if they are paying below parity with the remainder of the rate increase spread equally among the classes. This option is consistent with what was done in the settlement of the 2001 general rate case. The third option was to move half way to parity with the constraint that no class' rate increase is greater than 150% of the average increase and no increase is less than 50% of the average increase.

The Company is recommending approval of the third policy in the interest of balancing rate stability and equity, with a few exceptions. Smaller increases may be justified in instances where competitive pressures would result in a net margin loss were the general policy not modified. One example of this is the precedent of not moving classes such as street lighting and irrigation to parity since this would likely result in a permanent loss of part of this load. Under the Company's proposal, we are not anticipating that the proposed rate increase allocation will

cause any significant problems.

Q. Would you please summarize the electric parity ratios that resulted from the Company's cost of service analysis and the proposed rate spread?

A. The results of the Company's study and the proposed allocation are set forth in the last two columns in the following table. In addition, the table shows the parity ratios that result from the cost of service methodologies approved in the 1992 rate design case.

Customer Class	Parity Ratio Commission Basis	Parity Ratio	Proposed Rate Increase
Residential	99%	96%	7.35%
General Service, < 51 kW	104%	102%	3.8%
General Service, 51 - 350 kW	108%	115%	2.9%
General Service, >350 kW	96%	108%	2.0%
Primary Service	96%	101%	5.7%
All Electric Schools	87%	87%	8.6%
High Voltage – Retail Wheel	120%	125%	2.9%
High Voltage	90%	90%	8.6%
Lighting Service	86%	86%	8.6%
Firm Resale	90%	94%	8.6%
System Total / Average	100%	100%	5.7%

Four retail rate classes pay less than parity: residential, all electric schools, retail high voltage, and lighting customers. The results in the table and exhibit assume that the fourth annual adjustment to the Rate Schedule 26 and 31 rates have been

made, in accordance with the current versions of those schedules. The proposed rate spread is presented in Exhibit No.___ (JAH-4).

Q. Are there any rate classes where the half way to parity approach was moderated?

A. Yes. The irrigation customers, interruptible schools, high voltage , and lighting classes had their rate increase limited to 1.5 times the average rate increase. In addition, the high voltage retail wheeling class and Rate Schedule 25 were given the "minimum" increase of 2.86%. Moderation of rate increases is appropriate in the situation where rates are sufficient to cover marginal costs but additional increases would drive customers to competitive alternatives. This is the case of irrigation rates in Kittitas County. Retention of the load at the proposed rate levels will provide a significant contribution to margin, and result in lower rates to other customers assuming that the alternative is reduced sales and no margin contribution. This is also the case with lighting services.

Q. How were cost of service customer, energy, and demand relationships translated into rate design?

A. The Company used the energy and demand relationships as a guide in setting demand rates and energy rates. In the 2001 general rate case the Company adjusted demand rates to line up demand charges with the cost of service study. The current cost of service study indicates that the demand charges are still in line with the cost of service study sponsored by Ms. Paulson. As a result, we again

used the cost of service demand study to establish demand revenue targets.

The basic charge was derived from cost of service in the manner accepted by the Commission in UE-920499, except that one enhancement was made: part of the line transformer costs for residential and secondary general service customers are recovered in the basic charge.

V. ELECTRIC RATE DESIGN

Q. Has the Company prepared new tariffs based upon the rate spread proposal?

A. Yes, the proposed tariffs are presented in Exhibit No.___ JAH-5. In this section of my testimony, I will describe the new rate initiatives and the principles used to adjust existing rates.

Q. Has the Company included a revised index of rate schedules with this filing?

A. No. In order to avoid the need to file substitute tariff sheets during the period of time from when the tariff sheets included in this filing are suspended and when they are approved, the Company plans to file its revised index at the time new schedules go into effect.

Q. Please summarize the Company's electric rate design initiatives.

A. The Company proposes to gradually move the transformer cost into the basic charge starting with moving approximately one-third of the cost in this rate case. In addition, the Company is proposing to reblock the residential rate at 800 kWh,

instead of the current 600 kWh, and decrease the differential between the blocks. Finally, the Company is proposing to include a provision in Rate Schedule 26 for customers to take service at primary voltage based upon a cost-based differential.

Q. Would you please summarize the approach used to adjust rates to recover the revenue increase assigned to each class?

A. The Company started by developing a cost-based basic charge for each class. In past rate cases, the cost basis was derived from the meter costs, billing costs, and service line costs. As discussed later, the Company is proposing in this case to include part of the line transformer cost as well. The remaining revenue requirement was allocated to proforma billing determinants as follows:

- Residential Service: The first block was increased to 800 kWh to increase the recovery of nonvariable distribution costs in the first block, resulting in a 16% block differential.

- Small General Service (Rate Schedule 24): An equal percentage increase was applied to the summer and winter energy rates.

- Medium General Service (Rate Schedule 25): First, the demand rates were adjusted by the average rate increase. Second, the remaining revenue requirement after the basic charge and demand revenue was spread on an equal percentage basis.

- Large Secondary and Primary General Service (Rate Schedules 26 & 31):

The target demand charge revenue was taken from the cost of service study and the winter and summer rates were increased to recover the target revenue while maintaining the current seasonal differential. The energy and kVARH components were all given an equal percentage increase.

- Irrigation Rates (Rate Schedule 29): The winter charges and basic charge were tied to Rate Schedule 25. The summer demand was adjusted to maintain the current summer / winter ratio and the remainder of the increase was spread to the summer energy rates.

- Interruptible All-Electric Schools: An equal percentage increase was applied to all components of this closed rate schedule.

- High Voltage Full Requirements (Rate Schedules 46 & 49): The demand charge was left unchanged and not reduced based upon the cost of service study. The remainder of the increase was spread to the energy rates.

- Lighting Schedules: An equal percentage increase was applied to all components with the exception of the pole rental rates on Rate Schedules 55 and 88, which were equalized.

- Power Supplier Choice and Retail Wheeling (Rate Schedules 448 & 449): All the allocated distribution and sub-transmission charges are recovered on the demand charge.

Additional detail about the rationale for this rate design follows.

Q. Are any changes being proposed to the Conservation or Low Income rates?

A. No.

A. Modification of the Basic Charge Methodology

Q. What is the rationale for including the line transformer in the basic charge?

A. In the 1992 rate design case, there was extensive discussion about what should be included in the basic charge. At the time, the Commission adopted the "Basic Customer method" which includes the service line, meter, and meter reading cost. The Commission indicated that the charge should only recover those costs properly associated with each customer. Including the cost of the transformer is consistent with this principle because a transformer is installed specifically to serve a particular customer. Once installed, the transformer represents a fixed cost of providing service to the customer. PSE has used its databases to track the assignment of transformers to each customer class.

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

A. No, there are variations. Within the residential class, the variations are largely driven by the density of customers. In the case of higher densities, there is a load component to the transformer cost. In the case of the non-residential classes, there is generally a load component. In recognition that there can be a load component to the cost of the transformer, the Company is not proposing to recover the full cost of the transformer in the basic charge.

B. Modification to the Residential Rate Design

Q. Is the Company proposing another change to the residential basic charge?

A. Yes. In addition to modifying the basic charge to include part of the costs of the transformer, the Company is also proposing to increase the first block from 600 to 800 kWh to reduce under recovery of nonvariable costs through volumetric rates.

Q. What is the rationale for selecting 800 kWh as the break point?

A. The Company considered a number of alternatives for block designs and settled on the proposed 800 kWh design based upon balancing customer impacts with the need to decrease reliance on the more elastic part of the consumption to recover non-variable costs. In the 1992 rate design case, the parties discussed changing the first block. At that time, the Commission expressed a preference to leave the first block at 600 kWh to fairly allocate the benefits of the lower-cost hydro system and to provide customers with a proper price signal. The Company is aware of those concerns, but believes it is time to revisit these issues.

As a result of declining hydroelectric contracts and a growth in customers, the residential hydro allocation is currently on the order of 375 kWh per residential customer. The Company considered going back to a three-block rate in order to preserve the hydro allocation approach. However, the benefits of a simpler two-block rate design are preferred. In addition, providing a low cost block where approximately 35% of the customer bills do not exceed the first block does not provide a signal to those customers to conserve even though all customers have

usage on the margin. For example, why should an electric heat customer that does not have a choice for a different heating energy source bear the full weight of a marginal price signal, while a gas heat customer who can make choices about conservation is exempted? The third concern is the Company's exposure to distribution system cost under recovery as a result of declining consumption per customer.

Q. How was the differential between the first and second block set?

A. The Company increased the first block rate by 10% prior to applying the rate increase. The 10% number was derived as a balance between the objectives of recovering nonvariable distribution costs in a more equitable manner while moderating bill impacts to lower energy using customers.

Q. Is the Company proposing any change to the Residential Exchange?

A. No.

Q. Have you estimated the impacts of the proposed rate changes?

A. Yes. The impacts are shown in Exhibit No.___ (JAH-6). The Exhibit shows that the two rate designs are comparable for a typical customer.

Q. What changes are being proposed for non-residential rates?

A. The Company is proposing moving approximately one-third of the transformer costs into the basic charge.

Q. Would you please outline the rationale for the Company's proposal to have up to three annual rate adjustments for residential customers?

A. As previously noted, the Company is faced with the situation where there is a downward trend in consumption per customer that is creating pressure on recovering the nonvariable distribution costs. The Company considered a number of approaches for addressing this issue including: (i) significant changes to rate design such as increasing fixed cost recovery under facility charges; (ii) a return to decoupling of customer costs with sales; and (iii) implementation of an annual rate adjustment mechanism. The Company's proposal is to select the simplest option, an annual rate adjustment.

Q. Is this adjustment being proposed for non-residential customers?

A. No. Non-residential commercial electric consumption per customer is declining but the changes in non-residential consumption are strongly influenced by the economy and do not have the clear downward trend exhibited by the residential customer class.

Q. Why don't the proposed rate increase and customer growth address the issue of declining usage per customer?

A. The rate changes proposed in this case help address the problem. However, continued heavy reliance on volumetric rates to recover delivery costs does not permit PSE to recover those costs as long as customer use is declining. Customer growth does not address the issue because the line extension policy provides a

customer credit for the distribution costs that will be recovered in the incremental sales to the new customer. In short, the revenues from the new load are required to reimburse the Company for the incremental cost of the new delivery facilities, and do not cover costs incurred to replace or enhance the existing system.

Q. Would you please outline the Company's specific proposal?

A. I reviewed the Company's forecast of declining usage per customer and have noted that residential usage is dropping approximately 1.5% per year. Based upon this analysis, the proposal is to increase the rates in each class by 1.5% times the portion of the bundled rate that is determined to be T&D based upon PSE's cost of service study. This results in the annual increase shown in Exhibit No. ___(JAH-7). The Company's proposal is that there will be a maximum of three annual rate increases. Should the Company have a general rate increase prior to the implementation of the third adjustment, the unimplemented adjustments would be cancelled.

Q. What is the status of Rate Schedules 26 and 31?

A. During the 2001 general rate case, interested parties agreed that these schedules should move towards reflecting a cost based differential between large general service secondary and primary voltage rates. The plan (and existing schedules) included four annual rate adjustments to lower the rates under secondary voltage service Rate Schedule 26 (whose customers were significantly above parity) and increase the rates on primary voltage service Rate Schedule 31 (which as a class

was below parity). The proposed rate design takes into consideration the final two adjustments, slated for July 1, 2004 and 2005. The Company also considered this goal in its rate design in this case and allocated the smallest rate increase to Rate Schedule 26 and the average rate increase to Rate Schedule 31.

Q. As a result of these changes will there be a cost-based differential between the rates in Rate Schedules 26 and 31?

A. The rates will be much closer than they have been, but there will still be about a 3% difference between the two rates for an average customer after accounting for the cost-based differential.

Q. What is the Company's proposal for dealing with the remaining differential?

A. The Company's ultimate goal is to have a single tariff with a transformation adjustment for customers who prefer to take service at primary voltage. Therefore, the Company is proposing to add provisions to Rate Schedule 26 to offer customers a $0.18 / kW reduction of the Rate Schedule 26 demand charges if they provide their own transformation. In addition, customers who provide their own transformation and are metered on the primary side of the transformer will receive a 2% discount to the Rate Schedule 26 energy rates. Customers who still qualify for service under Rate Schedule 31 can take primary service under that schedule. However, customers who prefer primary service but are otherwise ineligible to take service under Rate Schedule 31 will have the option for primary service under Rate Schedule 26. It is anticipated that the Company will propose

in a future rate case to close Rate Schedule 31 to new customers.

VI. GAS RATE SPREAD

Q: What rate spread policy factors did the Company consider in developing its natural gas rate spread recommendation?

A: The Company proposes to continue to use the cost of service study as a guide to allocating the rate increase, however, the Company also took into consideration the customer impacts. In the cost allocation study presented by Ms. Paulson seven classes were below parity and three classes are above parity. As with the case for electric rate spread, the Company's proposal is to balance between reliance on the cost of service study and other factors including rate spread and precedent and customer impacts. In each class, I recommend that the Company average rate increase be adjusted to move each class' revenue levels closer to the cost of serving as presented by Ms. Paulson. In general, classes significantly above or below parity were targeted to 150% / 50% of the average increase and customer moderately above / below parity were targeted a 125% / 75% of the average increase and classes within 110% of parity were given the average increase.

Q: What treatment is proposed for the rate classes that have negative returns?

A: The CNG and Water Heater Rental class continue to have negative returns. The decline for CNG is a result of fixed costs and program administration costs spread over smaller volumes. This class was given an average increase since the CNG facilities are jointly used by the Company and the customers where the Company

accounts for the vast majority of the through-put. The water heater rental program has declining revenues and higher depreciation expense as a result of the settlement in the 2001 general rate case. As noted by Ms. Luscier in her testimony, Exhibit No. ____(BAL-1T), the subsidy by the other classes has declined since the last rate case. Since this class is below parity and it is anticipated that the class can absorb another larger than average increase without a significant drop in rentals, an increase of 150% of average was assigned to this class.

Q: Would you please summarize the natural gas parity ratios that resulted from the Company's cost of service analysis and the proposed rate spread?

A: The results of the Company's study and the proposed allocation follow.

Class	Parity Ratio	Proposed Increase
Residential 23/53/16	95%	6.92%
C & I Heating 31/36/61/51	119%	4.63%
C & I – 41	131%	3.65%
Rate Schedule 85	80%	3.77%
Rate Schedule 86	98%	4.96%
Rate Schedule 87	51%	2.55%
Rate Schedule 57	171%	8.99%
Special Transport Contracts 99/199/299	77%	0%
CNG Service 50	9%	7.85%
Rentals 71/72/74/75	59%	22.85%
Company	100%	6.32%

The special contract customers were not assigned an increase since there rates are set by prior contracts approved by the Commission. The water heater rental class

receives the highest percentage increase since they have no volumetric charges associated with their rates.

VII. GAS RATE DESIGN

Q. Has the Company prepared new tariffs reflecting the proposed rate spread?

A. Yes. The new natural gas tariff is presented in Exhibit No.___ (JAH-9) and the rate design is presented in Exhibit No.___ (JAH-8).

Q. Please summarize the proposed changes to the natural gas tariff?

A. The primary focus of the natural gas rate design is on residential Rate Schedule 23, where the Company is proposing to decrease the distribution margin charge and implement a facilities charge. The facilities charge is designed to reduce the dependence on volumetric charges for recovery of nonvariable delivery costs including the service line. In addition, a minor revision to Rate Schedule 57 is proposed to clarify the customer's obligation upon terminating service under this transportation schedule.

Q. How was the rate increase assigned to each class designed into rates?

A. The Company relied heavily on precedent and started with the setting of the customer charge based upon the customer cost study resulting from the cost of service study. A review of the cost of meter reading, billing, metering, and service lines indicated that in most cases the current customer charge is too low. The treatment of the residential customer charge cost is covered in the residential

rate design. For the non-residential classes the Company targeted going to the full customer charge as defined by the cost of service analysis, or targeted moving half way to the cost-based charge in cases where the costs would increase by over a hundred dollars a month. In the case of Rate Schedules 57 and 87 where there is significant movement between the schedules, the Company set the two customer charges at the same rate.

The demand charges for Rate Schedules 41 were based upon guidance from cost of service subject to a targeted cap of 150% of the average margin increase. This resulted in a 27% increase to the demand charge. The same approach was used for Rate Schedules 57, 85, 86, and 87 demand charges which also received a 27% increase. (As with the current rates, the demand charges for the those four rates are equiavalent.) The remaining revenue requirement for multiple block rates was targeted to equal increases while maintaining the current block differentials. .

Q. Please describe the rationale for implementing a facility charge under Rate Schedule 23?

A. Like the electric delivery system, the natural gas delivery system generally represents a fixed cost that Company recovers over rates that are based on the volume of gas a customer uses. This is problematic to the Company because declining usage per customer (representing a cumulative loss in margin) and because of the variation in recovery due to the high sensitivity of usage to temperature (a temporal issue that on average does not cause a loss in margin). The Company considered a number of solutions to address the under recovery of

its nonvariable costs for the gas system, including blocking the residential rate, weather normalization clauses, and decoupling. The preferred solution is the simplest solution: the facilities charge.

Q. Is the facilities charge a new approach?

A. Facilities charges are not common, but they have been discussed in a number of regulatory forums in the context of "fixed charges" or "two-part" rates. The argument for two-part rates from an economic efficiency perspective is that the customer should see the marginal costs for each of the services that they purchase. In the residential gas rate, the commodity service and the delivery service are separate products in the tariff and on the customer's bill. Since most of the distribution costs are fixed, a low marginal cost for this service represents efficient pricing.

Q. Are there customer benefits to the facility charge?

A. Yes, just as the fixed charge has revenue stability benefits for the Company, it also provides bill stability benefits to the customer. During cold weather, with corresponding higher gas heating requirements, the customer faces a higher bill for the increased commodity. The reduction of the variable distribution rate will result in a smaller bill increase during that period and reduced seasonal rate shock.

Q. Would you describe the Company's specific proposal?

A. The Company is proposing to implement a facilities charge of $7.50 / month in conjunction with increasing the basic charge to $6.50. This will reduce the margin charge by approximately $0.10 / therm. Since most of the distribution charge is fixed, one could support a higher facilities charge from both a cost basis and economic efficiency basis. However, the $7.50 level was selected to strike a balance with customer rate impacts. In addition the sum of the proposed facilities charge and proposed basic charge is slightly below the cost of fixed customer costs of meter reading, billing, the customer meter, and the service line.

The cross-over point where the facilities charge is bill-neutral is approximately 72 therms / month. At this level of usage, approximately 35% of the customer bills will have increased less than the class average increase and approximately twenty percent of the residential customers will have annual bill changes greater than fifteen percent. The customers with the largest increases are the small volume users, on the order of thirteen therms per month. As a result of this change, the Company will still have approximately 52% of its fixed delivery costs recovered through volumetric rates. The impacts of the proposed design are shown in Exhibit No.___ (JAH-10).

Q. Is the Company proposing a mechanism for addressing declining per-customer usage by residential gas customers?

A. Yes, a mechanism is proposed for the same reasons that one should be applied to residential electric customers. In the case of the gas customers, the annual adjustment is smaller as a result of a lower decline in annual consumption and the

proposal to institute a facilities charge. If the facilities charge proposal is rejected or decreased, the annual rate adjustment should be increased to reflect that more revenue will be lost for each percentage reduction in load. The proposed gas adjustment rate (assuming approval of the proposed facilities charge) is shown in Exhibit No. ___ (JAH-7).

Q. Are you proposing any other gas rate design changes?

A. The Company is proposing a clarification to Rate Schedule 57. The purpose of the clarification is to ensure that customers pay for any remaining gas imbalances when the customer leaves transportation service. Likewise, the Company will reimburse the customer for any over deliveries by the customer's supplier.

Q. Are any changes being proposed to the commodity rates or the PGA?

A. No, the PGA rate is not changing. However as a result of the cost of service study the revenue related adjustment to the commodity rate in Rate Schedule 101 increased from 1.04454% to 1.04779%.

Q: What Exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following Exhibits:

- **Exhibit No.___ (JAH-2)** Qualifications
- **Exhibit No.___ (JAH-3)** Results of the Weather Normalization
- **Exhibit No.___ (JAH-4)** Electric Proposed Rate Spread and Rate Design

- **Exhibit No.___ (JAH-5)** Proposed Electric Tariffs
- **Exhibit No.___ (JAH-6)** Impacts Of The Proposed Electric Rate Changes
- **Exhibit No.___ (JAH-7)** Residential Rate Adjustment Mechanism
- **Exhibit No.___ (JAH-8)** Natural Gas Proposed Rate Spread and Rate Design
- **Exhibit No.___ (JAH-9)** Proposed Natural Gas Tariffs
- **Exhibit No.___ (JAH-10)** Impacts Of The Proposed Natural Gas Rate Changes

Q. Does this conclude your testimony?

A. Yes.

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