EXHIBIT NO.___ (JHS-1T)
DOCKET NO. UE-04____/UG-04____
2004 PSE GENERAL RATE CASE
WITNESS: JOHN H. STORY

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
JOHN H. STORY (NONCONFIDENTIAL)
ON BEHALF OF PUGET SOUND ENERGY, INC.

APRIL 5, 2004

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY OF JOHN H. STORY

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY OF JOHN H. STORY

I. INTRODUCTION

Q. Please state your name, business address, and present position with Puget Sound Energy.

A. My name is John H. Story. I am the Director of Cost and Regulation at Puget Sound Energy. My business address is 10885 N.E. Fourth Street, Bellevue, Washington, 98009.

Q. Would you please provide a brief description of your educational and business experience?

A. Please see Exhibit No.___ (JHS-2).

Q. What topics are you covering in your testimony?

A. I will present the calculation of the adjusted test period, ratebase, working capital, conversion factor and the overall revenue requirement for the electric results of operations. I will explain the various adjustments to the results of operations for the current test year and, after taking into account these adjustments, present the adjusted test period and the resultant revenue requirement. Based upon the adjusted test period revenues of $1,425,200,434 for sales to customers, the total requested electric revenue increase is $81,446,431 which is an average 5.71% increase.

I also present the impact of the general rate case adjustments on the Power Cost Baseline Rate used in the Power Cost Adjustment (PCA) Mechanism.

Q. Please explain your Exhibit No.___ (JHS-E3).

A. The first page of this exhibit, Summary page, presents the unadjusted operating income statement and Average-of-the-Monthly-Averages ratebase for the Company as of September 30, 2003. Each of these items is then adjusted for the summarized proforma and restating adjustments. The revenue deficiency is added to the adjusted income statement and the impact on the operating income statement is presented. The rest of the exhibit is composed of two sections, described below.

Pages E3-A through E3-D of this Exhibit No.___ (JHS-E3) present a summary schedule of all the proforma and restating adjustments. The first column of numbers, on page E3-A, is the unadjusted net operating income for the year ended September 30, 2003 and the unadjusted ratebase for the same period. Each column to the right of the first column represents a proforma or restating adjustment to net operating income or ratebase. Each of these adjustments has a supporting schedule, which is referenced by the page number shown in each column title.

The last column, shown on page E3-D of the summary schedule, summarizes all of the adjustments and is the adjusted test period results used to calculate the revenue deficiency.

II. ELECTRIC AND COMMON ADJUSTMENTS

Q. Please describe each adjustment, explain why it is necessary, and identify the effect on operating income or ratebase.

A. I will explain the adjustments generally in the order as they are shown on the summary schedule.

Temperature Normalization

This adjustment pro forms revenue to a level, as shown on Exhibit No.___ (JHS-E3), page E3-A, column 2.01, which would have occurred, had the temperatures during the test year been normal. The difference between the actual Generated, Purchased and Interchange (GPI) and temperature normalized GPI is adjusted for system losses, allocated to the rate classes, and the revenue impact (based on the applicable end step energy rate for each rate class) is calculated. *See* Mr. James Heidell's testimony, Exhibit No.___ (JAH-1T), for a discussion regarding the allocation to the rate classes based on the proposed rate class level weather normalization methodology.

Net operating income is increased by $4,369,788 as a result of this adjustment.

Q. Please describe how the test year delivered load was normalized.

A. Test year GPI load of 20,641 MWH were temperature normalized using a technique that is comparable to that used by many utilities. The temperature normalization process requires that an estimated relationship (coefficients) between daily customer load and observed temperatures be calculated. Heating degree days (HDD) and cooling degree days (CDD) are used to reflect this temperature sensitive portion of load. It is necessary to have separate temperature (or HDD and CDD) estimated coefficients for each month because of changing temperature-load relationships during the year. With these estimated coefficients, temperature normalized load can be approximated by multiplying the coefficients by normal temperatures (in this case the thirty year average temperature 1973-2002). The result is temperature normalized load for the test year which can be compared to actual test year load to determine the test year temperature load adjustment. In this case, the test year temperature load adjustment is 97,905 MWH, or 91,638 MWH when adjusted for losses. This adjustment is the same methodology as what the Company used in its rebuttal case in the Power Cost Only Rate Case (PCORC) filing, Docket No. UE-031725. As agreed to in that filing, the Company will be meeting with Commission Staff, plus other interested parties, to attempt to reach consensus on a methodology for normalizing electric loads. If these discussions result in a change to the methodology the Company has used for this calculation, the Company will update its calculation once the changes are identified.

Q. Please continue with your discussion of the proforma and restating adjustments.

A. The next adjustment is:

<u>General Revenues</u>

This is a restating and proforma adjustment, as shown on Exhibit No.___ (JHS-E3), page E3-A, column 2.02, which removes from operating revenues all rate schedules that are a direct pass through of specifically identified costs or credits to customers, such as municipal taxes, the conservation rider, low income program, and residential exchange. A proforma adjustment has been included that reflects the revenue that would have been collected during the test year if the PCORC revenues had been implemented at the beginning of the test period. For purposes of this general rate case filing, we have used the Company's rate increase as presented in the rebuttal testimony of the PCORC proceeding. We will correct this adjustment when the Commission Order in Docket No. UE-031725 is issued if the amount is different.

Net operating income is increased by $123,253,360 as a result of these adjustments.

Power Costs

This schedule, shown on Exhibit No.___ (JHS-E3), page E3-A, column 2.03, adjusts the test year power cost to reflect the power cost resources that will be used during the rate year. The calculation of rate year normalized power cost is explained in Ms. Julia Ryan's testimony, Exhibit No.___ (JMR-1T), and is shown in Exhibit No.___ (JMR-10). This adjustment and the Sales for Resale-Secondary adjustment are calculated using 60-year water, for the reasons described in the testimony of Mr. Jeffrey Dubin, Exhibit No.___ (JAD-1T). As the last general rate case used 40-year water, a work paper showing the equivalent power costs has been provided to all parties.

Net operating income is decreased by $38,095,594 by this adjustment.

Q. Will you update the Power Cost Adjustment (PCA) baseline rate in this proceeding?

A. Yes. The schedule shown on Exhibit No.___ (JHS-4) adjusts the PCA baseline rate to reflect the new Power Cost Baseline. The methodology applied is consistent with that set forth in the PCA Settlement Agreement, under Docket No. UE-011570, and the PCA Compliance Settlement Agreement, under Docket No. UE-031389.

Q. Please continue describing the restating and proforma adjustments?

A. The next adjustments are:

<u>Sales for resale-Secondary</u>

This adjustment, shown on Exhibit No.___ (JHS-E3), page E3-A, column 2.04, adjusts the revenue for Sales for Resale/Other Utilities and Wheeling for Others to the levels determined by Ms. Julia Ryan as shown on her proforma power cost schedule, Exhibit No.___ (JMR-10).

Net operating income is decreased $114,160,749 by this adjustment.

<u>Federal Income Taxes</u>

This schedule adjusts actual Federal Tax expense to the restated level based on the test year for this case. As our normal tax year ends December 31st, this adjustment recalculates the test year using expenses and a tax adjustment for the twelve months ended September 30, 2003 and removes the current tax year estimates from the test period.

The effect of this adjustment, shown on Exhibit No.___ (JHS-E3), page E3-A, column 2.05, is to decrease net operating income by $4,651,347.

Tax Benefit of Proforma Interest

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-A, column 2.06, uses a ratebase method for calculating the tax benefit of proforma interest. As adopted by this Commission in prior rate cases, the customers receive the tax benefit associated with the interest on debt used to support ratebase and construction work in progress that has associated tax deductible interest. The effect of this adjustment is to decrease net operating income by $7,835,231.

Depreciation and Amortization

Test year depreciation has been restated based on the Average of Monthly Averages using the rates from the depreciation study performed in 2001 and applied in the Company's last general rate case Docket Nos. UE-011570 and No. UE-011571. An adjustment to annualize the amortization of WUTC authorized AFUDC has also been made.

This restating and proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-A, column 2.07, decreases net operating income by $149,619 and decreases ratebase by $74,810.

Conservation

This restating and proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-B, column 2.08, removes the amortization associated with the conservation rider. A proforma adjustment removes amortization related to the 1995 Conservation Trust as the Trust will be fully amortized by the rate year, and the ratebase has been reduced accordingly. A proforma adjustment has been made to remove the affect of one time credits that represent refunds to customers, related to various transactions that were processed through the conservation rider.

The effect of this adjustment is to increase net operating income by $26,189,031, and decrease ratebase by $11,569,864.

Bad Debts

This restating adjustment calculates the bad debt rate by using the actual amounts from the test year, consistent with prior rate cases. The bad debt percentage for the rate year is calculated by taking the actual write-offs for the test year and dividing them by the net revenues for the test year. The net revenues from line 1 are multiplied by the bad debt percentage, line 3, to determine the amount of bad debt for the rate year. This amount is compared to the test year level of bad debt expense on line 6 to determine the effect on income. This new percentage is also used in the conversion factor when determining the final revenue requirement.

This adjustment, as shown on Exhibit No.___ (JHS-E3), page E3-B, column 2.09, increases net operating income by $49,046.

<u>Miscellaneous Operating Expense and Ratebase</u>

This restating and proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-B, column 2.10, adjusts the test year for various items. Incentive plan payments based on a calendar year have been adjusted to the twelve months ended September 30, 2003 and associated payroll taxes have been adjusted accordingly.

A restating adjustment has been made to reflect a reduction in the level of steam sales to Georgia Pacific.

A restating adjustment has been made to annualize the effect upon ratebase of utility property that had been transferred from future use to non-utility during the test year.

A restating adjustment has been made to increase ratebase for construction work in progress that was in service but had not been transferred to plant in the test year.

The effect of these adjustments is to lower net operating income by $273,174 and to increase ratebase by $1,711,055.

<u>Property Taxes</u>

This proforma adjustment, shown Exhibit No.___ (JHS-E3), page E3-B, column

2.11, reflects the estimated property tax levy rates to be paid in 2004 based upon 2003 value. These rates will be adjusted to actual during the course of this proceeding.

The effect of this adjustment is to lower net operating income by $2,496,853.

<u>White River Licensing</u>

This proforma adjustment, shown on shown Exhibit No.___ (JHS-E3), page E3-B, column 2.12, adds to ratebase the Company's Licensing, and other costs deferred in accordance with the Company's Accounting Petition filed in December 2003, Docket No. UE-032043. Included in this amount are Licensing charges of $15,201,438, costs related to water rights acquisition of $2,585,017, and other safety and regulatory costs of $2,758,997. Amortization of the total amount of $20,545,452, over a 10-year period, is also reflected in this adjustment. As discussed by Mr. Eric Markell, Exhibit No.___ (EMM-1CT), the customers have received the benefit of these expenditures as the Company was able to keep the plant in operation during the 1983 through 2003 time period that the license process and subsequent appeal were underway, thereby avoiding higher cost market power during that time period. Since the beginning of the licensing process, these costs had been included in construction work in progress in compliance with FERC accounting requirements. When the FERC license requirements were not accepted by the Company, these costs were moved to Deferred Debits per the Accounting Petition in Docket No. UE-032043. As proposed in the Accounting Petition, the Company is now requesting recovery of these costs by recording the costs in Account 182 and including the average balance of these costs in ratebase for the rate period. The Company continues to operate the diversion dam in accordance with an agreement with the Army Corp of Engineers, and expects to invoice the Corp for the related operating costs incurred.

The effect of this adjustment is to decrease operating income by $1,335,454 and increase ratebase by $19,518,180.

Filing Fee

This restating adjustment, shown on Exhibit No.___ (JHS-E3), page E3-B, column 2.13, adjusts the test year estimates to actual expense for the Washington filing fee.

The effect of this adjustment is to decrease net operating income by $143,941.

Director and Officer Insurance

This restating adjustment, shown on Exhibit No.___ (JHS-E3), page E3-B, column 2.14, removes the portion of Director and Officer insurance that should be allocated to Company subsidiaries. The amount is determined by dividing non-utility assets by Puget Sound Energy, Inc. assets and applying that percentage to this insurance cost.

The effect of this adjustment is to increase net operating income by $26,853.

Montana Energy Tax

This restating adjustment, shown on Exhibit No.___ (JHS-E3), page E3-B, column 2.15, adjusts the test year amount of this tax to the amount that would be incurred during the rate year based on the power generated as reflected in the power cost adjustment.

The effect of this adjustment is to decrease net operating income by $107,939.

Interest on Customer Deposits

This proforma adjustment to operating income is the result of customer deposits being treated as a reduction to ratebase. This proforma adjustment adds the cost of interest for this item to operating expense. This presentation is consistent with decisions in prior general rate cases, and as shown on Exhibit No.___ (JHS-E3), page E3-C, column 2.16, reduces net operating income by $151,631.

SFAS 133

This restating adjustment, shown on Exhibit No.___ (JHS-E3), page E3-C, column 2.17, removes the effect of SFAS 133, which represents gains or losses recognized for derivative transactions but is not considered for rate making purposes.

The effect of this adjustment is to increase net operating income by $555,963.

Rate Case Expenses

As in prior general rate cases, this proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-C, column 2.18, calculates the remainder of costs related to the 2001 rate case to be amortized in the rate year. It totals the expected costs for this case, includes the rate case costs for the Power Cost Only Rate Case (PCORC), Docket No. UE-031725, and amortizes these costs over three years. This adjustment will be updated during the course of the proceeding to reflect actual costs incurred.

The PCORC rate case costs are being included in this adjustment per the methodology the Company proposed in its September 2003 Accounting Petition, Docket No. UE-031471. The costs for the PCORC rate case reflect the Company's incremental legal and consulting costs associated with presenting that case. The Company is requesting recovery of these costs as this proceeding is a necessary cost of doing business which is not ordinary and ongoing. As such, these are the type of expense that have been allowed to be deferred and recovered over a reasonable period. The WUTC has recognized the recovery of this type of expense as being in the public interest and sound regulatory theory. They are a legitimate expense incurred whenever the Company must represent itself before the Commission.

The effect of this adjustment is to decrease net operating income by $465,668.

<u>Property Sales</u>

The purpose of this restating and proforma adjustment is to provide the customer with the net gains or losses from sales of utility real property since the last general rate case. The amount of the net gain is amortized over a three-year period, with the deferred amount included in working capital.

This adjustment, shown on Exhibit No.___ (JHS-E3), page E3-C, column 2.19, decreases net operating income by $2,918,307.

<u>Property and Liability Insurance</u>

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-C, column 2.20, reflects the expected contractual increases for property and liability insurance. This adjustment will be updated during the course of the proceeding.

The effect of this adjustment is to reduce net operating income by $969,645.

<u>Pension Plan</u>

This restating adjustment, shown on Exhibit No.___ (JHS-E3), page E3-C, column 2.21, adjusts the test year to reflect cash contributions to the Company's qualified retirement fund. During 2003 the Company made this deductible cash contribution, determined by its plan actuary, to the Pension Plan to help ensure that the plan remains fully funded. As allowed in prior general cases the Company has averaged the last four years of contributions and is requesting that average amount in current rates. This adjustment also restates the expense associated with the Supplemental Executive Retirement Plan to an average of the last four years expense.

The effect of this adjustment is to reduce net operating income by $5,556,828.

<u>Wage Increase</u>

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-C, column 2.22, reflects the impact of wage increases and payroll tax changes. For represented (union) employees, the adjustment annualizes the wage increases granted in 2004, 2005, and 2006. The percentage of wage increase for IBEW union employees from the test period through the rate year are 3% effective April 1, 2003, 3% effective April 1, 2004, and 3% effective April 1, 2005. The percentage of wage increase for UA union employees from the test period through the rate year are 4.5% effective October 1, 2002, 4.5% effective October 1, 2003, 3% effective October 1, 2004, and 3% effective October 1, 2005. The percentage of wage increase for management employees from the test period through the rate year are 3% effective March 1, 2003, 3% effective March 1, 2004, and 3% effective March 1, 2005. These management increases have been weighted by prior year actual salary increases, as in prior general rate cases.

This adjustment decreases net operating income by $2,766,991.

Investment Plan

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-C, column 2.23, adjusts the Company portion of investment plan expense to reflect the additional expense associated with the wage increases and is based on the current contribution rates.

Net operating income is decreased by $119,893 as the result of this adjustment.

Employee Insurance

This proforma adjustment updates the test year insurance payments to the amount that will be experienced in the rate year. For represented employees, the estimated cost is based on the average Company contribution amount of $620 (3/03 –6/05) and $682 (7/05-4/06) per eligible employee per month. The amounts are the result of negotiations between PSE and the IBEW union and PSE and the UA union. The same average rate was also applied per salaried employee.

These costs are allocated to expense, construction and other accounts based on the percentage of payroll charged to these accounts during the test year. The portion of the insurance payments associated with expense during the test year has been determined to be 67.73%. This adjustment corrects the amounts actually charged to expense to reflect the appropriate 67.73% allocation.

The effect of this adjustment, shown on Exhibit No.___ (JHS-E3), page E3-C, column 2.24, is to decrease net operating income by $870,145.

<u>Montana Corporate License Tax</u>

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-D, column 2.25, adjusts this tax to the current taxable income computed in the proforma income tax adjustment. This Corporate License Tax is based upon Federal taxable income.

The effect of this adjustment is to decrease net operating income by $1,274,583.

<u>Storm Damage</u>

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-D, column 2.26, reflects the difference between the test year expense level of "normal" storms to that of the six-year average. The six-year average is used to determine the annual expense allowed for ratemaking purposes. Also, deferred balances related to catastrophic storms are amortized over three years. This adjustment would not be impacted for this proceeding by the proposal presented by Ms. Susan McLain to change this category of adjustment to catastrophic events as described in Exhibit No.___ (SML-1CT).

The effect of this adjustment is to increase net operating income by $366,405.

Frederickson Plant

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-D, column 2.27, reflects the inclusion of the Company's investment in and operating costs of the Frederickson 1 Generating Plant. This amount is the same amount proposed by the Company and Commission Staff in the PCORC hearings, adjusted to reflect the average amount that would be in ratebase for the rate year in this proceeding. This adjustment will be trued up to projected costs based on the actual recording of this plant addition once the various regulatory approvals are received and the transaction closes.

The effect of this adjustment is to decrease net operating income by $2,665,480 and increase ratebase by $74,634,936.

Low Income Amortization

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-D, column 2.28, removes amortization of the Company's Low Income Program. Such costs are recovered through a rider outside of general rates.

The effect of this adjustment is to increase net operating income by $3,801,853.

Regulatory Assets

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-D, column 2.29, adjusts the regulatory assets (Tenaska, Cabot, and BEP), net of deferred federal income taxes to their projected rate year AMA balances.

The effect of this adjustment is to decrease ratebase by $45,394,988.

Production Adjustment

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page E3-D, column 2.30, decreases production related ratebase and certain production expenses by the same production factor which was used by Energy Supply Planning for calculating power costs. The production factor used in this calculation is the ratio of the test period normalized delivered load to the rate year delivered load which is 98.719%. This equates to the 1.281% reduction applied to these various power related costs.

Net operating income is increased by $578,628 and ratebase is decreased by $10,215,426 as the result of this adjustment.

Working Capital

The purpose of this calculation is to provide a return for the funds the shareholder has invested in the Company, for utility purposes, over and above the investment in plant and other specifically identified ratebase items already earning a rate of return.

The first part of this adjustment calculates the total average invested capital that has been utilized during the test year. From the average invested capital, the operating investment, which is already earning a return, is deducted. A second deduction is made for nonoperating assets and plant not in service. The result is total working capital provided by the shareholder.

This total working capital is then allocated between nonoperating working capital and operating working capital using the method consistent with previous rate cases. The resulting operating working capital represents the shareholder's average investment which is required to provide utility service but which would otherwise not earn a return.

This proforma adjustment, shown on Exhibit No.___ (JHS-E3), page 4.01, increases ratebase by $59,592,732.

Cost of Capital

This schedule, shown on Exhibit No.___ (JHS-E3), page 4.02, reflects the proposed capital structure for the Company during the rate year and the associated costs for each capital category. The capital structure and costs are presented in the testimony of Mr. Donald Gaines, Exhibit No.___ (DEG-1CT). The rate of return is 9.12%.

Conversion Factor

The conversion factor, shown on Exhibit No.___ (JHS-E3), page 4.03, is used to adjust the net operating income deficiency by revenue sensitive items and Federal income tax to determine the total revenue requirement. The revenue sensitive items are the Washington State utility tax, Washington WUTC filing fee, and bad debts. The conversion factor used in the revenue requirement calculation, taking into consideration the adjustments discussed earlier, is 62.00972%.

Allocation Methods

Common Utility Plant is that portion of utility operating plant that is used for providing more than one commodity, i.e., both electricity and gas, to customers. Thus, common plant includes costs associated with land, structures, and equipment which are not charged specifically to electric or gas operations because the assets are used jointly by both departments. The Company allocates its common utility plant in determining ratebase by using the four-factor allocation method as authorized in the merger stipulation. Components of the four-factor allocator include the number of customers, direct labor charged to O & M, Transmission and Distribution O & M, and net classified plant (excluding general plant).

Common operating costs are those costs that are incurred on behalf of both electricity and gas customers. The Company incurs common costs related to:

Customer Accounts Expenses; Customer Service Expenses; Administrative and General Expense; Depreciation/Amortization; Taxes Other Than Federal Income Tax (FIT); and FIT. The most appropriate allocation method is applied consistently to each type of common cost. Allocation methods used include: (1) twelve month customer average; (2) joint meter reading customers; (3) non-production plant; (4) four factor allocator; (5) direct labor; and (6) current tax.

For purposes of calculating the working capital allowance, the Company applies the most appropriate of the allocation methods to each common balance sheet account.

Allocation methods used and the calculations thereof are shown on Exhibit No.___ (JHS-E3), page 4.04.

General Rate Increase

This schedule, shown on Exhibit No.___ (JHS-E3), page 4.05, is a summary of proforma and restated ratebase and net operating income. Based on $2,658,121,651 invested in ratebase and $191,820,286 of net operating income, before deduction of the residential and farm exchange credit shown separately on Residential Exchange Schedules, the Company would have a retail revenue deficiency of $81,600,769 before allocation of $154,338 to wholesale customers.

III. ADJUSTMENTS TO THE POWER COST BASELINE RATE

Q. Please define the term Power Cost Baseline Rate.

A. In PSE's last general rate case, the Commission approved the parties' Settlement Stipulation for Electric and Common Issues ("Settlement Stipulation"). *See* Docket Nos. UE-011570 and UG-011571, Twelfth Supplemental Order (June 20, 2002) ("Twelfth Supplemental Order"). Among other things, the Twelfth Supplemental Order authorized the use of a Power Cost Adjustment (PCA) Mechanism as a method for adjusting PSE's power costs. The Commission subsequently approved substitution of certain revised exhibit pages to the PCA Mechanism in its Fifteenth Supplemental Order, Docket Nos. UE-011570 and UG-011571, (May 13, 2003) ("Fifteenth Supplemental Order"). A copy of the approved Settlement Terms for the Power Cost Adjustment Mechanism, Exhibit A to Settlement Stipulation, as revised, is provided in Exhibit No.___ (JHS-5).

The PCA Mechanism sets forth an annual accounting process for a sharing of costs and benefits between PSE and its customers over four graduated levels (so-called "bands") of power cost variances, with an overall cap of $40 million (+/-) over the four year period July 1, 2002 through June 30, 2006. The PCA Mechanism distinguishes between power costs and all other costs included in general rates. The PCA Mechanism includes a table that shows the allocation of costs between power costs that are included in the Power Cost Baseline Rate, and non-power costs. Two categories of costs comprise the Power Cost Baseline Rate: variable rate components and fixed rate components.

Q. When are the accumulated PCA sharing and deferral amounts reviewed?

A. In August of each year, PSE files an annual report detailing the power costs included in the deferral calculation for the period ending June 30 of each year. PSE's first PCA Compliance filing was addressed in Docket No. UE-031389.

Q. Is the Company requesting that any accumulated PCA costs be added to the general rate increase requested in this proceeding?

A. No. The accumulated costs do not exceed the trigger amount necessary to request an increase or decrease in the power cost rate, and it is not expected at this time that this threshold will be met during the course of this proceeding.

Q. How is the Power Cost Baseline Rate adjusted?

A. Independent of the yearly accounting and adjustment for power cost variances, PSE may also apply to the Commission to true up the Power Cost Baseline Rate to all power costs in a power cost only rate case, which does not include an update for cost of capital, or in a general rate case, which would include an update to the current cost of capital. A general rate case true up requires, among other things, testimony and exhibits that include

- Adjustments to the Fixed Rate Component
- Adjustments to the Variable Rate Component
- A calculation of proforma production cost schedules that are consistent with the general rate case filing, including power supply and other adjustments impacting then-current production costs.

My testimony and exhibits in this general rate case filing provide this required information in support of PSE's present application to true up its Power Cost Baseline Rate.

Q. Would you please describe the adjustments used to determine the new Power Cost Baseline Rate?

A. As stated earlier, the PCA Mechanism makes a distinction between power cost only costs and all the other costs determined in a general rate case. In a general rate case, the Company uses a future rate year to determine certain power costs and then pro forms those costs back to the test year. The proposed rate year used for these adjustments is March 2005 through February 2006. For this proceeding we have used the test year September ended 2003.

In addition to the general rate case adjustments discussed earlier, as was done in the PCORC filing, we have provided a proforma adjustment to account for changes to PSE's ratebase and operating expenses associated with the purchase of Frederickson 1.

Q. Please explain what Exhibit No.___ (JHS-4) represents.

A. Exhibit No.___ (JHS-4) is equivalent to Exhibit A-1 Power Cost Rate set forth in the original PCA Settlement, but as updated to reflect the power cost changes proposed in this general rate case filing. The net of tax rate of return shown on line 7 of this Exhibit No.___ (JHS-4), 7.78%, is the net of tax rate of return being requested by the Company in this proceeding. The test period power costs have been allocated in the same manner between fixed and variable costs and the total of these costs are then adjusted for revenue sensitive items. Following the same methodology set forth in Exhibit A of the PCA Mechanism, this result is then divided by the test year load to calculate the new Power Cost Baseline Rate of $48.951 per MWH before revenue sensitive items.

Q. Please explain the remaining pages included in Exhibit No.___ (JHS-4).

A. The remaining pages of this exhibit are equivalent to the Exhibits A-2 through E set forth in the PCA Settlement, as updated to reflect the changes in power costs presented by the Company for this general rate case filing. In the upper left hand corner of each of these pages is the reference to the exhibit being replaced in the original PCA Mechanism.

Q. How will the new Power Cost Baseline Rate be implemented, as the proposed rate year does not match the original PCA period of July through June?

A. Each month the Company calculates the potential over or under collection of power costs for the PCA. For the fixed cost component of the PCA, we assume that these costs are collected equally over the twelve month period. Once we have the new rate approved in this filing, we will change this part of the calculation to reflect the new monthly fixed costs allowed in the PCA for the remaining months of the PCA period.

As the estimated variable costs are adjusted to the actual variable costs we will treat these costs in the same manner as the current PCA calculation. We will then deduct for any adjustments required under the PCA mechanism, including, for example, the Schedule E Contract Adjustments. Exhibit E for the third PCA period will be divided into two rate periods: one eight-month period limited to current PCA contract rates, the other four-month period limited to the new PCA contract rates. The monthly total of the above adjustments will then be compared to an individual month's kWh's times the new Power Cost Baseline Rate and this variance will be the amount that will be considered in the sharing mechanism of the PCA.

The total of each month's variance for the PCA period will determine if there is any refund or collection of power costs required for the PCA period, after consideration of the various PCA bands and caps.

Q. Does this conclude your testimony?

A. Yes.

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