EXHIBIT NO. ___(JHS-1T)
DOCKET NO. UE-06___/UG-06___
2006 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-06____ Docket No. UG-06____

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
JOHN H. STORY
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, 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 electric results of operations and PSE'S proposals for a Depreciation Tracker and other mechanisms to address regulatory lag and attrition for both electric and gas. I also describe the allocation of common expenditures between electric and natural gas.

With respect to electric results of operations I present the calculation of the adjusted test period, ratebase, working capital, conversion factor and the overall revenue requirement. I will explain the various adjustments to the results of operations for the test year for this proceeding 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 $1,615,403,012 for sales to customers, the total requested electric general rate case revenue deficiency is $140,908,878 which represents an average 8.72% increase. This increase does not reflect an additional Production Tax Credit associated with the new Wild Horse wind powered electric generation project, which is expected to provide an additional credit to customers' bills during the rate year of $18.7 million, or the impact of the Depreciation Tracker discussed below. In addition, the Company will update its projection of rate year power costs during the course of this proceeding. This update could result in an increase or decrease to the Company's total requested electric general rate case revenue deficiency. I will also discuss these topics later in my testimony.

I also present the Company's proposed changes to its Power Cost Adjustment ("PCA") Mechanism and its related exhibits.

Finally, I discuss a new mechanism, the Depreciation Tracker, which the Company is proposing to help alleviate certain regulatory lag and attrition impacts associated with adding transmission and distribution infrastructure to the Company's natural gas and electric systems. The additional revenue requirement associated with the Tracker mechanism is $7,878,988, .49%, for electric and $10,884,680, 1.16%, for natural gas over current revenues.

The total rate increase requested, when the general rate case revenue deficiency and the Depreciation Tracker are combined, is $148,787,866, which is an average 9.21% increase, for electric service and $51,324,638, which is an average 5.44% increase, for gas service. (The general rate revenue deficiency for natural gas is $40,439,958, 4.28% on adjusted test period revenues of $943,846,610 as discussed in the testimony of Mr. Karl Karzmar, Exhibit No. ___(KRK-1T))

II. TEST YEAR FINANCIAL STATEMENTS AND RATEBASE

Q. Would you please explain Exhibit No. ___(JHS-3)?

A. Exhibit No. ___(JHS-3) presents the actual electric financial statements for the test year before any pro-forma or restating adjustments. Page 1 of this exhibit presents a comparison between the unadjusted electric income statement for 9/30/2003, the test year for PSE's last general rate case, Docket No. UG-040640 et al. (the "2004 general rate case"), and the unadjusted electric income statement for 9/30/2005, the test year for this general rate case filing. Page 2 of the exhibit presents the electric balance sheet for the same time periods and page 3 of the exhibit presents the ratebase calculation for the test year for this case prior to any pro forma and restating adjustments. Mr. Karzmar presents the equivalent schedules for natural gas operations in his Exhibit No. ___(KRK-3)

Q. Is the ratebase calculation done in the same manner as allowed in the last general rate case?

A. Yes, with two exceptions. The first difference is that the deferred tax accounts that were related to indirect overheads have been removed from ratebase, consistent with the Commission's order on October 26, 2005, approving the Company's accounting petition in Dockets UE-051527 and UG-051528.

Q. Please describe the background and outcome of Dockets UE-051527 and UG-051528.

A. The Company had previously taken a deduction for certain general overhead costs associated with construction, which created a deferred tax balance of approximately $72 million. This balance was offset against electric and natural gas ratebase in the 2004 general rate case. The IRS then changed the method of deduction for these costs and requires any utility that had previously deducted these items to reverse the deductions over the 2005 and 2006 tax years.

The accounting petition requested that the Company be allowed to set up a regulatory asset account to track the carrying costs associated with the tax payments based on the turn around of the deductions associated with these overheads. These tax balances have been removed from gas and electric ratebase. The deferred tax balances are treated as operating investment in the working capital calculation. For the electric calculation this is shown on page 4 of Exhibit No. ___(JHS-3), for the test year.

The Commission's order allowed the Company to defer the carrying cost associated with the payment of these taxes during the last quarter of 2005 and during 2006, but left open the question over what period of time these deferred costs should be amortized to be collected from customers. I will discuss the Company's proposed amortization schedule for these deferred costs later in my testimony.

Q. What is the second difference in the ratebase calculation as compared to the 2004 general rate case?

A. The second change in the calculation of ratebase is that deferred tax balances on the balance sheet are treated consistent with direction from PSE's Tax Department, as described in the memo from Mr. Matthew Marcelia, PSE's Director Tax, which is provided as Exhibit No. ___(JHS-13C).

The calculation of the test year ratebase with these two adjustments, but before restating and proforma adjustments, is shown on page 3 of Exhibit No. ___(JHS-3).

Q. Would you please explain the working capital calculation?

A. The purpose of this calculation is to provide a return on the funds the shareholders have invested in the Company for utility purposes that have not been invested in plant or other specifically identified ratebase items already earning a rate of return. The calculation is based on the average of the monthly averages of the actual amounts in the asset and liability accounts for the test year.

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 earning a return, or is excluded from earning a return, is deducted. A second deduction is made for non-operating assets and plant not in service. The result is total working capital provided by the shareholders.

This total investor supplied working capital is then allocated between non-operating working capital and operating working capital using the method consistent with previous rate cases which is the ratio of operating or non-operating investment to the total operating and non-operating investment. The resulting operating working capital represents the shareholders' average investment which is required to provide utility service but which would otherwise not earn a return. The electric working capital calculation is shown in Exhibit No. ___(JHS-3), page 4.

Q. Please describe the final page of Exhibit No. ___(JHS-3).

A. The final page of this Exhibit presents the Allocation Methods, or factors, used in allocating common expenditures between electric and natural gas.

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. 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 in providing service to both electric and gas customers. The Company allocates its common utility plant in determining ratebase by using the four-factor allocation method as authorized in the stipulation approving the merger of Puget Sound Power & Light Company and Washington Natural Gas Company. Components of the four-factor allocator include the number of customers, direct labor charged to operations and maintenance ("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; and Current and Deferred Income Taxes. The most appropriate allocation method based on type of cost is applied 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; (6) current tax and (7) deferred tax.

III. ELECTRIC PRO FORMA AND RESTATING ADJUSTMENTS

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

A. The first page of this exhibit, Summary page, presents the unadjusted operating electric income statement and Average-of-the-Monthly-Averages ratebase for the Company as of September 30, 2005 in the column labeled Actual Results of Operation. The various line items are then adjusted by the summarized proforma and restating adjustments, as shown in the third column. This column is the source used to calculate the revenue deficiency. In the second to last column the revenue deficiency is added to the adjusted income statement and the impact on the operating income statement and ratebase is presented in the final column. The rest of this exhibit is composed of two sections, described below.

Pages 4-A through 4-D of this Exhibit No. ___(JHS-4) present a summary schedule of all the proforma and restating adjustments. The first column of numbers, on page 4-A, is the unadjusted net operating income for the year ended September 30, 2005 (the test year) 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 second to the last column, shown on page 4-D of the summary schedule, summarizes all of the adjustments and the final column shows the adjusted test period results used to calculate the revenue deficiency.

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 in the same order as they are shown on the summary schedule, by reference to the column number and title of each adjustment.

4.01 <u>Temperature Normalization</u>

This adjustment, as shown on Exhibit No. ___(JHS-4), page 4-A, column 4.01, pro forms test year delivered load and revenue to a level which would have been expected to occur had the temperatures during the test year been "normal". The difference between the actual test-year Generated, Purchased and Interchange ("GPI") load of 21,613,588 MWH and the temperature normalized GPI is adjusted for system losses. The result of this calculation is then allocated to the rate classes. The revenue impact (based on the applicable end step energy rate for each rate class) is then calculated.

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

A. Dr. Jeffrey Dubin's testimony, Exhibit No. ___(JAD-1T), describes the Company's weather normalization models and methodology. Mr. James Heidell's testimony, Exhibit No. ___(JAH-1T), discusses the allocation to the rate classes based on the proposed rate class level weather normalization methodology. Generally, 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. Separate temperature (or HDD and CDD) coefficients are used for each month to capture changing temperature-load relationships during the year. With these coefficients, one approximates what the load would have been during the test year if temperatures had been no colder or warmer than "normal" by multiplying the coefficients by "normal" temperatures – an average of actual observed temperatures over time. The result is an estimate of temperature normalized load for the test year which is then compared to actual test year load to determine the test year temperature load adjustment.

The test year was warmer than normal requiring an adjustment of net operating income to bring revenues up to what is estimated would have occurred under normal conditions. The temperature load adjustment increases actual generated, purchased and interchange by 145,418 MWH, or 135,823 MWH when adjusted for line losses. After allocation to the different customer classes, this results in an increase to net operating income of $6,999,127.

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

A. The next adjustment is:

4.02 <u>General Revenues</u>

This is a restating and proforma adjustment, as shown on Exhibit No. ___(JHS-4), page 4-A, column 4.02, 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, the low income program, and the residential exchange credit provided by the Bonneville Power Administration. The associated expense for these direct pass through tariffs are removed in the other restating and proforma adjustments with the exception of the municipal tax expense which is removed on line 39 of this adjustment.

In addition, a proforma adjustment is included to reflect the revenue that would have been collected during the test year if the General Rate Case revenues from the 2004 general rate case and from PSE's 2005 power cost only rate case, Docket UE-050870 ("2005 PCORC"), had been in effect during the entire test period. The Company will update this adjustment so that it reflects the change in revenues associated with the updating of the power cost baseline rate as of July 1, 2006, as required in the 2005 PCORC final order, when that change becomes known. This adjustment will be required in part to properly reflect the fact that Schedule 95, the PCA Mechanism schedule, will be going to a zero rate effective with new rates associated with this Docket. At that time, the revenues associated with Schedule 95 will effectively be moved to general rate schedules.

Net operating income is increased by $158,740,864 as a result of these adjustments.

4.03 Power Costs

This schedule, shown on Exhibit No. ___(JHS-4), page 4-A, column 4.03, adjusts the test year power cost, Sales for Resale/Other Utilities and Wheeling for Others to reflect the power costs that are projected to be incurred during the rate year. The calculation of rate year projected power cost is explained in Mr. David Mill’s testimony, Exhibit No. ___(DEM-1CT), and is shown in Exhibit No. ___(DEM-10). Rate year power costs are adjusted to test year power cost levels by a “production factor” discussed later in my testimony.

This adjustment will be updated at the same time as the General Revenues adjustment is updated for the July 1, 2006 power cost baseline update so that PSE’s rate year power cost projection reflects a more current estimate of what power costs are projected to be during the rate year. This update could increase or decrease the Company's power cost calculation.

Q. Are the costs of the Muckleshoot Indian Tribe settlement discussed by Mr. Olin reflected in this adjustment?

A. Yes. This adjustment is included in line 17, Hydro and Other Power costs. This pro-forma adjustment is one third of the $1,422,798 payment before applying the production factor.

Q. What is the total change to net operating income for all the power cost changes?

A. Net operating income is decreased by $194,324,715 by the power costs adjustments.

Q. Will you update the Power Cost Adjustment Mechanism's Baseline Rate in this proceeding?

A. Yes. The schedule shown in Exhibit No. ___(JHS-9C), discussed later in my testimony, adjusts the PCA Power Cost Baseline Rate based on the pro forma and restating adjustments made to power costs and production plant. The methodology applied to calculate the Baseline Rate is consistent with the Company's 2005 PCORC filing.

Q. Please continue describing the restating and proforma adjustments?

A. The next adjustment is:

4.04 <u>Federal Income Taxes</u>

This schedule adjusts actual Federal Income Tax ("FIT") expense to the restated level based on the test year for this case. As PSE's normal tax year ends December 31, this adjustment recalculates the test year using expenses and tax adjustments for the twelve months ended September 30, 2005. The effect of this adjustment, shown on Exhibit No. ___(JHS-4), page 4-A, column 4.04, is to increase net operating income by $4,553,313.

4.05 <u>Tax Benefit of Proforma Interest</u>

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-A, column 4.05, uses a ratebase method for calculating the tax benefit of proforma interest. Consistent with the approach 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 $2,442,428.

4.06 Conservation

This restating and proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-B, column 4.06, removes the amortization associated with the conservation rider. The associated conservation revenues were removed in Adjustment 4.02.

A restating adjustment has also been made to remove the effect of a one time credit that represents a benefit passed through to customers that was associated with the Centralia sale in compliance with the Commission Order in Docket No. UE-991409.

The effect of this adjustment is to increase net operating income by $11,852,001, and decrease ratebase by $28,822.

4.07 Bad Debts

This restating adjustment calculates the appropriate bad debt rate by using the average bad debt percentage for three of the last five years of history after removing the high and low years, which is the method used in PSE's 2004 general rate case. Each of the five years bad debt expense rate is calculated on the twelve months ended September 30 so that they are consistent with this filing's test year. The bad debt percentage for a given year is calculated by taking the actual write-offs for that year and dividing that by the net revenues for that year. The net test year revenues on line 6 is then multiplied by the three year average bad debt percentage, line 8, to determine the amount of bad debt expense. This amount is compared to the actual test year level of bad debt expense on line 11 to determine the effect on income. This bad debt percentage is also used in the conversion factor when determining the final revenue requirement. This adjustment, as shown on Exhibit No. ___(JHS-4), page 4-B, column 4.07, is a decrease to net operating income of $1,044,352.

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

This restating and proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-B, column 4.08, adjusts the test year for several different items.

1. <u>Amortization of Deferred Taxes Regulatory Asset</u>

The first adjustment is to pro form in the amortization of the regulatory asset associated with the deferred taxes discussed earlier in my testimony related to indirect overheads. (As discussed above, the IRS has changed the method of deduction for these indirect overhead costs and requires any utility that had previously deducted these items to reverse the deductions over the 2005 and 2006 tax years.) The Commission's order on October 26, 2005, approving the Company's accounting petition in Dockets UE-051527 and UG-051528, allowed the Company to set up a regulatory asset account to track the carrying costs associated with the tax payments based on the turn around of the deductions associated with these overheads. The Commission allowed the Company to defer the carrying costs, with interest, associated with the deferred taxes that had to be repaid to the Federal Government in 2005 and 2006. This adjustment amortizes this deferral over two years and includes the amortization of the carrying costs associated with the declining balance of this regulatory asset. The Company is proposing to amortize these costs for recovery over two years because that is the Company's recent experience regarding how often it needs to file general rate cases.

2. <u>Amortization of Baker Hydro Project Seismic Studies</u>

The next adjustment pro forms the amortization of the costs associated with the seismic studies required to be performed in compliance with the Company's existing license for its Baker hydroelectric project. These costs were authorized to be deferred in Docket No. UE-021577, and it is expected that the amortization of the costs will begin in the spring of 2006. The amortization is based on a five year schedule as directed in the Commission's order in Docket No. UE-021577.

3. <u>Oregon Property Taxes for 3rd AC</u>

In the 2004 general rate case, the Commission allowed the Company to normalize the cost associated with the Oregon property taxes associated with the 3rd AC transmission line. This expense was to be recovered over three years starting March 2005. This proforma adjustment normalizes the test year to reflect that recovery over the three year period.

4. Baker Hydro Project Relicensing Costs

This adjustment is associated with the relicensing of the Baker hydroelectric project which is discussed in Mr. Olin's testimony. This adjustment amortizes the cost of this relicensing over the life of the license, 45 years.

5. Tree Watch Expense

The adjustment line labeled "Tree Watch" pro forms in the $2 million expense allowed in the 2004 general rate case. Tree Watch had previously been deferred and amortized. In the 2004 general rate case, the parties proposed that this program be expensed as incurred with a minimum of $2 million per year being incurred to maintain the program. As the change in tracking this program occurred during the test year for this case in March 2005 with the implementation of the final order in the 2004 general rate case, this adjustment brings expense up to the allowed level, consistent with the Company's actual current and going-forward Tree Watch expenses.

6. New York Stock Exchange Fees

This adjustment pro forms in the change in cost for the Company's Common Stock Fees on the New York Stock Exchange ("NYSE"). In the fall of 2005, the SEC approved a restructuring of the fees assessed by the NYSE. The fees are based on the number of shares outstanding and this adjustment is based on estimated shares to be outstanding during 2007. This will be adjusted during the course of this proceeding to reflect changes in the amount of outstanding shares expected in 2007.

7 Depreciation Expense on Construction Work in Progress In-Service

This adjustment calculates the estimated depreciation expense associated with the construction work in progress that has been closed to in-service but is not yet classified to plant. The associated ratebase amount is discussed below.

8. Ratebase Adjustments

The first ratebase adjustment shown on this page is to add to ratebase construction work in progress ("CWIP") that is closed and in-service but not yet classified to plant. This adjustment is consistent with prior cases and is necessary to properly reflect the ratebase that was in service during the test year.

The next ratebase adjustment pro forms in the Baker Relicensing costs, net of amortization, and is associated with the Baker Project costs discussed above. Mr. Olin discusses, in his testimony, the Baker Relicensing and why these costs were necessary to obtain the new FERC license for this hydro project.

The effect of all these miscellaneous adjustments is to decrease net operating income by $3,136,640 and to increase ratebase by $27,382,430.

4.09 Property Taxes

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-B, column 4.09, reflects the estimated property tax levy rates to be paid in 2006 based upon 2005 value. This adjustment is done in the same manner as in the last general rate case, and the levy rates will be adjusted to actual during the course of this proceeding.

The effect of this adjustment is to decrease net operating income by $1,011,792.

4.10 Hopkins Ridge Wind Project

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-B, column 4.10, presents the ratebase and operating expenses associated with the Hopkins Ridge Wind Project for the rate year. The plant balance, shown on line 3 of this adjustment, is the sum of the estimated construction costs for Hopkins Ridge, $177,479,678. In his testimony, Exhibit No. ___(RG-1HCT), Mr. Garratt explains the difference between this lower expected construction cost and what was approved in Docket No. UE-05870.

Q. Please explain how the ratebase addition was calculated for rate purposes.

A. The estimated acquisition price less the accumulated depreciation and deferred taxes through the December 2007 time period is the amount that PSE used to calculate the return needed to cover the capital costs for the Hopkins Ridge Project. The elements of this calculation are described below.

Construction was finalized in November 2005. However, not all construction costs were completed or booked at that time. For the rate year costs, we assumed that the construction costs will be final prior to December, 2006 and be equal to the current estimate of capital cost. Using this amount, the Company calculated the average of the monthly averages plant balance for the rate period. We also calculated the accumulated depreciation and deferred taxes through the rate year based on an estimate as to when final capital costs would be closed to the plant accounts. This adjustment will be trued up to actual amounts closed to plant during the Spring of 2006, and the final plant balance, based on these closings, will be used to adjust this calculation during the course of these proceedings.

For book depreciation purposes, the Company is continuing to depreciate the Hopkins Ridge Project over 20 years (the engineering life certified by the turbine manufacturer), which is a 5% depreciation rate. The resulting monthly accumulated depreciation was then averaged in the same manner as the plant cost.

Deferred taxes associated with the tax depreciation of the plant were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h). This Section specifies how a future projection of a plant value, and its associated deferred taxes, must be treated for the normalization method of accounting when that asset is going to be included in rates. The methodology presents a calculation that allows deferred taxes to be deducted for ratemaking purposes if calculated based on the pro rata number of days for the future period that the plant investment is considered for inclusion in ratebase and is adjusted to match the average of the monthly averages used in determining the plant balance. The methodology we have used in this calculation is slightly different than that used in prior cases when adding rate year plant costs but is consistent with the method used in the 2005 PCORC. The different methodology is based on private letter rulings issued by the IRS, PLR 9202029 and PLR 9313008, which illustrate that the future prorated deferred taxes have to be averaged.

For the Hopkins Ridge Project, the deferred tax calculation is based on five-year tax depreciation for wind related facilities and 15 years for non-wind related assets such as transmission and distribution facilities for the plant. As the Hopkins Ridge Project was added to plant in the last quarter of 2005, the Company is required to use the mid-quarter convention in calculating the tax depreciation and the deferred tax benefit for the first year of operation instead of the half-year convention that would normally be used. The reason for this change is that with the addition of the Hopkins Ridge Project, more than 40% of the Company's capital expenditures were booked in the last quarter of the year. When this occurs, the Internal Revenue Code requires the Company to calculate tax depreciation and deferred taxes for that year based on each quarter's additions rather than use the mid-year convention. This reduces the amount of the tax depreciation and deferred tax for the plant added in the last quarter of the year.

However, this tax difference is picked up over the remaining tax life of the asset by the use of slightly higher tax depreciation rates in the following years.

These adjustments increase ratebase by $146,464,189.

Q. Please explain the other costs associated with the Hopkins Ridge Project on Exhibit No. ___(JHS-4) at page 4.10.

A. I explained depreciation expense (shown on line 15) above. Amortization of the prepaid transmission is based on the estimated wheeling expenditures that will be made to BPA and reflects the turn around of the regulatory asset the Commission approved in the 2005 PCORC order. The regulatory asset account tracks the prepaid transmission costs that BPA required the Company to provide for upgrading the transmission interface. These costs turn around based on the credit BPA uses to offset the demand component of the billing for transmission costs associated with this project. Property insurance, property taxes and production O&M are the Company's current estimate of these costs for the rate year.

The total of all these expenses is $16,219,881 as shown on line 26 of page 4.10 and decrease net operating income by $10,542,923.

4.11 Excise Tax and Filing Fee

This restating adjustment, shown on Exhibit No. ___(JHS-4), page 4-B, column 4.11, adjusts the test year to the actual expense for excise tax and the Washington filing fee that should be recorded for these costs.

The effect of this adjustment is to decrease net operating income by $384,314.

4.12 Director and Officer Insurance

This restating adjustment, shown on Exhibit No. ___(JHS-4), page 4-B, column 4.12, 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 $4,742.

4.13 Montana Energy Tax

This restating adjustment, shown on Exhibit No. ___(JHS-4), page 4-B, column 4.13, adjusts the test year amount of this tax to the amount that is projected to 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 increase net operating income by $8,557.

4.14 Interest on Customer Deposits

This proforma adjustment to operating income is the expense impact associated with using customer deposits 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-4), page 4-C, column 4.14, reduces net operating income by $227,184.

4.15 SFAS 133

This restating adjustment, shown on Exhibit No. ___(JHS-4), page 4-C, column 4.15, removes the effect of SFAS 133, which represents mark to market gains or losses recognized for derivative transactions. This accounting pronouncement is not considered for rate making purposes.

The effect of this adjustment is to increase net operating income by $592,392.

4.16 Rate Case Expenses

In the Company's 2004 general rate case the Commission allowed a portion of the Company's 2004 rate case expenses to be deferred and amortized over three years. At the same time, the Commission changed the method for future recovery of rate case expenses to a "normalized" methodology. Based on recent prior cases, a "normal" level of expense for filing a general rate case was then determined and divided by an estimated time interval of three years to determine the annual amount to set in rates (half of which were included in the electric revenue requirement and half of which were included in the gas revenue requirement). The same methodology was applied to determine a normalized amount of PCORC expense, except that the entire annual amount of normalized PCORC expense was included in the electric revenue requirement.

The Company has followed this method in the calculation of rate case expense for this case. The Company has used the history of expense levels for PCORC and general rate cases since 2001 to determine a normalized level of expenditures by averaging the costs associated with the last two general rate cases and the last two PCORC cases. This average level of costs was then spread over two years for each type of case, which more accurately reflects the actual time frame that has been experienced between general rate case filings and between PCORC filings over the past several years, and is consistent with the Company's anticipated future pace of rate case filings.

The average cost for a general rate case using this methodology is $4.3 million. This cost is allocated 50% to electric and 50% to natural gas, which results in a $1.07 million dollar annual cost for each energy group. The average cost for a PCORC case is $1.2 million. This cost is allocated to electric only for a $0.6 million dollar annual cost.

As to the deferred costs from the 2004 general rate case that the Commission ordered to be amortized for recovery over three years, the Company has used the yearly amount set in the 2004 general rate case to comply with the Commission order so that the amortization will be completed by March 2008. The resulting amortization and normalized cost are then compared to the amount the Company had recorded in the test year for regulatory expense and the result decreases net operating income by $97,273 as shown on Exhibit No. ___(JHS-4), page 4-C, column 4.16.

4.17 Property Sales

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 gains and losses are allocated to gas and electric based on the use of the property. The amount of the net gain is amortized over a three-year period, with the deferred amount being included in working capital. This adjustment is done in compliance with the settlement agreement for property sales from Docket UE-89-2688-T.

This adjustment, shown on Exhibit No. ___(JHS-4), page 4-C, column 4.17, decreases net operating income by $18,149.

4.18 Property and Liability Insurance

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-C, column 4.18, reflects the estimated premium increases for property and liability insurance expense. These costs are allocated between electric and natural gas dependent on the purpose of the insurance. This adjustment will be updated to actual premiums during the course of the proceeding.

The effect of this adjustment is to reduce net operating income by $29,325.

4.19 Pension Plan

This restating adjustment, shown on Exhibit No. ___(JHS-4), page 4-C, column 4.19, adjusts the test year to reflect cash contributions to the Company's qualified retirement fund. During 2003 the Company made a deductible cash contribution, as 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. The average contribution is allocated to electric and natural gas O&M based on salary distribution. This adjustment also restates the expense associated with the Supplemental Executive Retirement Plan to an average of the last four years expense and allocates this expense between electric and natural gas based on salary distribution.

The effect of this adjustment is to reduce net operating income by $2,565,770.

4.20 Wage Increase

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-C, column 4.20, reflects the impact of wage increases and payroll tax changes, as described in the testimony of Mr. Tom Hunt, Exhibit No. ___(TMH-1T). For represented (union) employees, the adjustment annualizes the wage increases granted in 2005, 2006, and estimated for 2007. The percentage of wage increase for IBEW union employees from the test period through the rate year are 3% effective April 1, 2005, 3% effective April 1, 2006, and 3% effective April 1, 2007. The percentage of wage increase for UA union employees from the test period through the rate year are 3% effective October 1, 2005, 3% effective October 1, 2006, and 3% effective October 1, 2007. The percentage of wage increase for management employees from the test period through the rate year are 3.04% effective March 1, 2005, 3% effective March 1, 2006, and 3% effective March 1, 2007. These management increases have been weighted by prior year actual salary increases, as discussed by Mr. Karzmar.

This adjustment decreases net operating income by $2,208,007.

4.21 Investment Plan

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-C, column 4.21, adjusts the Company portion of investment plan expense to reflect the additional expense associated with the wage increases and is based on the current employee contribution rates.

Net operating income is decreased by $94,453 as the result of this adjustment.

4.22 Employee Insurance

This proforma adjustment updates the test year insurance payments to the amount for the rate year. For represented employees, the estimated cost is based on the average Company contribution amount of $750 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 to salaried employees.

These costs are allocated to electric and natural gas based on payroll distribution and then 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 62.32%.

The effect of this adjustment, shown on Exhibit No. ___(JHS-4), page 4-C, column 4.22, is to decrease net operating income by $669,622.

4.23 Montana Corporate License Tax

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-D, column 4.23, adjusts this tax for the current taxable income computed in the proforma income tax adjustment and is done in the manner prescribed by the State of Montana for determining this tax liability.

The effect of this adjustment is to decrease net operating income by $239,361.

4.24 Storm Damage

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-D, column 4.24, reflects adjustment of the test year expense level of storm damage expense, $1,999,417, to the normal level of storm damage expense, which is based on the average of the most recent six-years. The six-year average storm damage expense, $5,470,194, is used to determine the annual expense allowed for ratemaking purposes, consistent with prior rate cases.

The next part of the adjustment allocates the balance of deferred costs related to catastrophic storms over three years. This amount will be amortized each year until the account balance is zeroed out.

The effect of this adjustment is to decrease net operating income by $197,617.

4.25 Regulatory Assets

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-D, column 4.25, adjusts the production related regulatory assets, net of deferred federal income taxes, to their projected rate year average of the monthly averages balances.

The effect of this adjustment is to decrease net operating income by $2,887,461 and decrease ratebase by $54,943,645.

4.26 Wild Horse Wind Plant

This proforma adjustment, shown on Exhibit No. ___(JHS-4, page 4-D, column 4.26, presents the ratebase and operating expenses associated with the Wild Horse Project for the rate year. The plant balance, shown on line 2 of this adjustment, is the sum of the estimated construction cost for Wild Horse, $383,295,532. In his testimony, Exhibit No. ___(RG-1HCT), Mr. Garratt explains these costs

Q. Please explain how the ratebase addition was calculated for rate purposes.

A. The estimated acquisition price less the accumulated depreciation and deferred taxes through the December 2007 time period is the amount that PSE used to calculate the return needed to cover the capital costs for the Wild Horse Project. The elements of this calculation are described below.

Construction is estimated to be finalized in December 2006. For the rate year costs we assumed that the construction costs will be final prior to December 2006 and will be equal to the current estimate of capital costs. Using this amount, we calculated the average of the monthly average plant balance for the rate period. We also calculated the accumulated depreciation and deferred taxes through the rate year. This adjustment will be updated during the course of this proceeding based on actual expenditures and adjustments to estimates.

In addition, as was approved for the Hopkins Ridge Project in the 2005 PCORC, the Company proposes to true up the costs of the Wild Horse Project to actual costs in the first annual PCA Mechanism compliance filing after the Wild Horse Project goes into service and the capital costs of the Project are finalized. The reason this true up is necessary is that final receipt of invoices and final capital expenditures on the project will continue for several months from the actual in-service date.

For book depreciation purposes, the Company is depreciating this asset over 20 years, which is a 5% depreciation rate, and is the same rate used for Hopkins Ridge. The resulting monthly accumulated depreciation was then averaged for the rate year in the same manner as the plant cost.

Deferred taxes associated with the tax depreciation of the plant were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h). This Section specifies how a future projection of a plant value, and its associated deferred taxes, must be treated for the normalization method of accounting when that asset is going to be included in rates. The methodology presents a calculation that allows deferred taxes to be deducted for ratemaking purposes if calculated based on the pro rata number of days for the future period that the plant investment is considered for inclusion in ratebase and is adjusted to match the average of the monthly averages used in determining the plant balance.. The methodology we have used in this calculation is slightly different than that used in prior cases when adding rate year plant costs but is consistent with the method used in the 2005 PCORC. The different methodology is based on private letter rulings issued by IRS, PLR 9202029 and PLR 9313008, which illustrate that the future prorated deferred taxes have to be averaged.

For the Wild Horse Project, the deferred tax calculation is based on five-year tax depreciation for the wind related assets and 15 years for non-wind related assets such as transmission and distribution facilities for the plant. As the Wild Horse Project is added to plant in the last quarter of 2006, the Company is required to use the mid-quarter convention in calculating the tax depreciation and the deferred tax benefit for the first year of operation instead of the half-year convention that would normally be used. The reason for this change in calculating deferred taxes is, as discussed above with respect to the Hopkins Ridge Project, that with the addition of the Wild Horse Project, more than 40% of the Company's capital expenditures will be booked in the last quarter of the year. When this occurs, the Internal Revenue Code requires the Company to calculate tax depreciation and deferred taxes for that year based on each quarter's additions rather than use the mid year convention. This reduces the amount of the tax depreciation and deferred tax for the plant added in the last quarter of the year. However, this tax difference is picked up over the remaining tax life of the asset by the use of slightly higher tax depreciation rates in the following years.

Wild Horse has another deferred tax that is associated with a timing difference for the royalty payments on this project, which are discussed by Mr. Garratt. For tax purposes, the royalty payment is considered an additional capital expenditure and is deferred and amortized over 15 years. For accounting and rate purposes, we have treated this as a cost of producing power and take a current tax deduction. This timing difference creates a tax receivable which has been added to the ratebase calculation. The amount of ratebase increase for the rate year is $199,782.

The total of all the ratebase adjustments increases ratebase by $354,783,949.

Q. Please explain the other costs associated with the Wild Horse Project on Exhibit No. ___(JHS-4) at page 4.27.

A. I explained depreciation expense (shown on line 9) earlier. The basis for the production O&M, plant property insurance and property taxes is discussed in Mr. Garratt's Exhibit No. ___(RG-1HCT). The transmission expense is based on the estimated transmission expenditures that will be made to BPA to bring the power to PSE's control area.

The total of all these expenses is $34,207,203 as shown on line 18, and decreases net operating income by $22,234,682.

Q. What is the total revenue requirement for the Wild Horse Project?

A. The revenue requirement is approximately $78,382,000 as adjusted to the test year by the production factor. I will explain the production factor later in my testimony in adjustment 4.32. To get the actual impact of Wild Horse, the production tax credits, plus the associated return on the production tax credit deferred tax asset, would have to be deducted from this amount. The net credit for the PTCs are valued at $18,721,000, for the test year. This reduces the revenue requirement for Wild Horse to $59,661,000.

Q. Does this mean that approximately 56% of the revenue deficiency in this case is associated with the Wild Horse Project?

A. No. As described in Mr. Mills' testimony, generation from the Wild Horse Project will reduce the level of wholesale market purchases that the Company must make. Without the Wild Horse Project, there would be an increase in test year purchased power of $41.6 million, gross of revenue sensitive items. Thus, the net impact of adding the Wild Horse Project is an increased revenue requirement of $18.1 million.

Moreover, the important revenue requirement impact that the Wild Horse Project will have on rates is the cost of this resource over its life compared to the alternatives. As explained in the testimony of Mr. James Elsea, Exhibit No. ___(WJE-1HCT), this is projected to be a net present value benefit to PSE's electric portfolio of greater than $50 million when compared with the cost of generic resources in the Company's 2005 LCP.

Q. Would you please explain what the Production Tax Credit is?

A. The Production Tax Credit ("PTC") is a subsidy provided by the U.S. Government for generating electricity from wind. The amount of the subsidy is currently 1.9 cents per kilowatt hour for wind generation and may be adjusted over time due to inflation adjustments. As of the date of this filing, this subsidy can be claimed for the first 10 years for a new wind project put into service prior to December 31, 2007. The use of the credit is restricted in that it can only be used to offset 25% of a company's current taxes payable. However, unused credits can be carried forward for up to 20 years.

Q. When will the PTCs for the Wild Horse Project be credited to the customer?

A. The Company proposes to use the PTC Tracker approved by the Commission in the 2005 PCORC as to PTCs for the Hopkins Ridge Project. As described in that case, the Company's PCA Mechanism does not currently provide a means for such pass through because it only includes tax accounts associated with production plant and production related regulatory assets. As mentioned above, the use of the tax credit is restricted to offsetting 25% of the Company's current taxes payable, with the possibility of being carried forward to future years' taxable income if it is not possible to utilize them in the current year. In addition, the tax credits are associated with the tax on the current year's taxable income, which is payable in quarterly installments during the year with any final payments being made in September of the following year. This creates a deferred tax account based on the timing difference between the generation of the tax credits associated with actual generation of electricity from the wind plant and how the tax credits would be utilized against current taxes for taxable income. This accounting impacts Account 236, current taxes payable, and Account 190, Accumulated deferred income taxes, which are not reflected in the PCA tracking.

Thus, to properly flow the Wild Horse Project tax credits through to the customer, the Company proposal is to use the approved PTC tracker that will pass through to the customer the actual production tax credits as they are generated. This pass through will be adjusted by the carrying costs for the deferred tax account for the

PTCs that have been generated but have not been used for the current year's tax credit. Because the customer is receiving the benefit of the tax credits as they are generated and the Company does not receive a credit from the IRS until the tax credits are utilized, the Company is reimbursed its carrying costs for funds through this calculation. As described in the 2005 PCORC hearing, this results in the customers and the Company being made whole with respect to tax credit timing.

Q. What is the result for this rate case?

A. The 2007 tracker for these credits, which has been estimated using the projected PTCs to be generated by the Hopkins Ridge Project and the Wild Horse Project, plus the estimated balance of the deferred tax account, is a credit of approximately $32.4 million. This calculation is shown on Exhibit No. ___(JHS-14). During the rate year, and thereafter, the actual PTCs generated by PSE's wind facilities and the return on the actual deferred tax balance will be compared to the amount included on customers' bills. Any difference between the actual amounts versus what was credited to customers will be used to adjust the tracker. PSE will also adjust the tracker for new estimates of PTCs based on a forward looking tax year. It is PSE's expectation that this tracker will be adjusted yearly to reflect these differences or a report will be filed showing why an adjustment is not necessary. As this tracker is not tied to a PCA period or a PCORC filing, and instead is tied to the Company's tax filings, the Company will file an update every

October for the next tax year with the ability to file sooner to adjust a tax year if the PTCs generated versus what were estimated for the tracker rate vary by more than 25%.

Q. Please continue with your explanation of pro forma and restating adjustments.

A. The next adjustment is:

4.27 <u>Incentive Pay</u>

This restating adjustment uses a four year history of incentive compensation made to employees. In his testimony, Mr. Hunt discusses why this expense is appropriate for ratemaking consideration and how the program is similar to the previously allowed incentive compensation programs.

For this calculation we have used the years 2002 through 2005 and allocated the four year average to electric and natural gas based on payroll distribution. The incentive is then allocated to O&M and other accounts based on where payroll was charged during the test year. This amount is then compared to actual expenses during the test year and results in an increase in net operating income of $707,914.

4.28 General Office and Crossroads Relocation

During the test year, the Company relocated employees from its Bellevue General Office Building and its Crossroads Building to the PSE Building. The purpose of the consolidation was to bring key work groups and support functions together and avoid the cost of a major upgrade that would have been required on the 50 year old General Office building. This restating adjustment removes the General Office and Crossroads Building from operating expense and ratebase. The adjustment also pro forms in the yearly cost associated with the lease of the PSE Building.

The effect of this adjustment is shown on Exhibit No. ___(JHS-4), page 4-D, column 4.28, and it decreases net operating income $1,350,727 and decreases ratebase $3,139,603.

4.29 Other Amortization

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-D, column 4.29, removes amortization associated with the Company's Low Income Program. Such costs are recovered through a rider outside of general rates, and the revenues associated with this program were removed in the revenue adjustment, page 4.02.

This adjustment also removes the administrative costs for the green power program. The revenue for this program is removed in the revenue adjustment, page 4.02, and the expense to purchase the green tags is removed in the power cost adjustment, page 4.03.

The effect these adjustments is to increase net operating income by $5,065,947.

4.30 <u>Demand Response Program</u>

This pro forma adjustment adds to the test year the costs associated with the Company's proposed expanded offering of demand response programs, which are presented in the testimony of Mr. Calvin Shirley, Exhibit No. ___(CES-1T).

The effect of this adjustment is shown on Exhibit No. ___(JHS-4), page 4-D, column 4.30, and it decreases net operating income by $1,950,000.

4.31 <u>Depreciation and Amortization</u>

Since the mid 1980s, an adjustment for test year depreciation expense and the WUTC AFUDC amortization (i.e., the Commission allowed AFUDC rate equal to the Company's allowed rate of return that is in excess of the FERC AFUDC rate) has been pro formed in a regulatory filing on an average of monthly average ("AMA") calculation based on the AMA plant balances included in the test period ratebase. The Company is proposing in this case that actual depreciation expense and WUTC AFUDC amortization for the test period be used in calculating the revenue deficiency unless there is a change in depreciation rates or there is a restatement needed to properly reflect depreciation expense.

Q. Why does the Company propose to change the way depreciation expense and WUTC AFUDC amortization are calculated?

A. For accounting purposes, the Company does not book depreciation expense or WUTC AFUDC amortization based on an AMA calculation because the information is not available on a monthly basis. Thus, the AMA adjustment only reflects the impact on a particular test year because no financial entry is made to reflect this adjustment. In addition, this adjustment is generally immaterial and can be positive one period and negative another. This adjustment makes no difference over an asset's depreciable life because the depreciation is based on the plant value and both methods allocate the plant value over its service life. The impact of this adjustment as proposed by the Company has no change to net operating income or ratebase.

We have provided a calculation of the AMA depreciation adjustment in the accounting workpapers in compliance with WAC 480-07-510(3)(b).

4.32 <u>Production Adjustment</u>

This proforma adjustment, shown on Exhibit No. ___(JHS-4), page 4-D, column 4.32, decreases production related ratebase and certain production expenses by the same production factor that was used 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 99.109%. This adjustment is applied to power cost related items so that the growth in load increases revenues to cover the rate year level of power costs. The ratio of test year delivered load to rate year delivered load equates to the .00891% reduction applied to these various power related costs. This adjustment is consistent with how the production expenses have been calculated in prior general rate cases and PCORCs.

Net operating income is increased by $819,902 and ratebase is decreased by $11,082,282 as the result of this adjustment.

This adjustment is the last Company adjustment for pro forma and restating adjustments.

IV. CALCULATION OF THE ELECTRIC REVENUE DEFICIENCY

Q. Would you please explain what is presented in Exhibit No. ___(JHS-5)?

A. This Exhibit presents the calculation of the revenue deficiency based on the pro forma and restated test period. The different pages in this Exhibit are:

5.01 <u>General Rate Increase</u>

This schedule, shown on Exhibit No. ___(JHS-5), page 5.01, shows the test period proforma and restated ratebase, line 1, and net operating income, line 6. Based on $2,973,018,835 invested in ratebase, an 8.76% rate of return and

$172,969,603 of net operating income, the Company would have a retail revenue deficiency of $140,908,878.

5.02 Cost of Capital

This schedule, shown on Exhibit No. ___(JHS-5), page 5.02, 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 8.76% and 7.57% net of tax.

5.03 Conversion Factor

The conversion factor, shown on Exhibit No. ___(JHS-5), page 5.03, is used to adjust the net operating income deficiency for revenue sensitive items and Federal income tax to determine the total revenue deficiency. 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 62.07334%.

V. APPLICATION OF AND PROPOSED CHANGES TO THE PCA MECHANISM

A. Brief Overview of the Current PCA Mechanism

Q. Please briefly describe the Company's existing PCA Mechanism.

A. In Docket Nos. UE-011570 and UG-011571, the Commission approved the parties' Settlement Stipulation for Electric and Common Issues ("Settlement Stipulation"). Among other things, the Twelfth Supplemental Order approving the Settlement Stipulation authorized the use of the PCA Mechanism as a method for adjusting PSE's power costs in between general rate cases. A copy of the approved Settlement Terms for the Power Cost Adjustment Mechanism, Exhibit A to the Settlement Stipulation, is provided in Exhibit No. ___(JHS-6).

The PCA Mechanism set forth an annual accounting process for a sharing of costs and benefits between PSE's shareholders and its customers over four graduated levels (so-called "bands") of power cost variances, with an overall cap on Company's share of costs of $40 million over the four year period July 1, 2002 through June 30, 2006. The power cost variances that are shared through the PCA Mechanism are certain power costs the Company actually incurs during a one-year period that are in excess of, or are less than, the level embedded in the rates paid by PSE's electric customers.

Q. How does one determine the level of power cost variance during a year?

A. The PCA Mechanism distinguishes between power costs and all other costs included in electric general rates. The PCA Mechanism includes a table that shows the allocation of costs between power costs included in the Power Cost Baseline Rate, and non-power costs. Two categories of costs comprise the Power Cost Baseline Rate: the variable rate components and the fixed rate components. These costs are projected in a general rate case or power cost only rate case in order to establish the Power Cost Baseline Rate that is embedded in rates charged to electric customers. After PSE's actual power costs for each year are reviewed in annual true-up filings, any power costs that are lesser or greater than the Power Cost Baseline Rate are subject to the sharing bands of the PCA Mechanism, with any excess costs or cost savings deferred and netted for future recovery or refund.

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

A. Under the PCA Mechanism as originally approved, PSE filed an annual report in August of each year detailing the power costs included in the deferral calculation for the period ending June 30. In the 2005 PCORC, the Commission approved changing the annual PCA periods so that they correspond to a calendar year, which is PSE's fiscal year. Starting in 2007, the annual report will be filed by March 31 for the period ending the previous December 31. The August report will no longer be necessary.

Q. Does this change have any implications for this filing?

A. The change to the timing of the annual PCA periods necessitated creation of a six month PCA period for July through December 2006 in order to address the "gap" between the end of PCA Period four at the end of June 2006 and the beginning of the new calendar PCA periods on January 1, 2007. The Commission approved for this transition period, setting the PCA Mechanism sharing bands at 50% of the previous allowed limits. In addition, because of the expiration of the $40 million cumulative cap on PSE's excess power cost exposure on June 30, 2006, the Power Cost Baseline Rate is to be updated in May for a July 1, 2006 implementation date. Thus, the 2005 PCORC order requires that the Power Cost Baseline Rate be updated in the middle of this rate case, as discussed earlier in my testimony.

Q. Is the Company requesting in this filing that any deferred PCA cost be included in rates in addition to the general rate increase?

A. No. The deferred costs do not exceed the trigger amount necessary to request an increase or refund of power costs, and it is not expected at this time that this threshold will be met during the course of this proceeding. In August 2006 the Company will file the annual PCA Mechanism compliance report for the PCA period ended June 2006. At that time, it is contemplated that a request for deferral recovery would be made for any amounts that have been deferred up to that time. This is required under the terms of the original PCA Mechanism, which calls for recovery upon expiration of the $40 million cap of amounts deferred during the period of time the cap was in effect. See Exhibit No. ___(JHS-6), Section 3.

B. Proposed Changes to the PCA Mechanism

Q. Is the Company proposing any changes to the PCA Mechanism in this filing?

A. Yes. Mr. Salman Aladin and Mr. Bertrand Valdman discuss in their testimonies the changes the Company is proposing to the PCA Mechanism sharing bands based on modeling the Company has conducted that helps quantify the risks associated with power cost volatility as wells as financial considerations that limit the Company's ability to absorb such risks. In addition, as described by Mr. Aladin and Ms. Kimberly Harris, the Company's proposed revised sharing bands would better align the interests of PSE's customers and shareholders with respect to power cost risks and the setting of the PCA Power Cost Baseline Rate in rate cases.

The Company is also proposing: (i) that Schedule E of the current PCA Mechanism be eliminated; and (ii) that costs associated with a new line of credit to support the Company's wholesale power market hedging transactions be added to the Power Cost Baseline Rate.

In his direct testimony, Exhibit No. ___(KRK-1T), Mr. Karzmar discusses the changes required for the Purchased Gas Adjustment ("PGA") to include the gas related costs associated with the new line of credit.

Q. What is Schedule E to the current PCA Mechanism?

A. Schedule E to the PCA Mechanism calculates any increase associated with certain long-term power contracts that have been approved by the Commission, such as the March Point and Sumas purchased power agreements and the purchased power agreements for the Company's Mid-C hydroelectric resources. If there is an *increase* in cost for these contracts in excess of what was set in the last general rate case or PCORC, the general rate case or PCORC contract rate is used to price the MWhs from the contract. By contrast, if there is a *decrease* in costs for these contracts, such decrease is passed through to the customer in the annual PCA true-up.

Q. Why is the Company proposing to eliminate Schedule E from the PCA Mechanism?

A. The Company does not believe that cost increases associated with these contracts should be ignored in determining the amount by which PSE's actual annual power costs have exceeded or fallen below the Power Cost Baseline Rate embedded in rates. These contracts have all been approved by the Commission, including the contract provisions providing for cost adjustments to be made under the contracts from time to time. Excluding such cost increases from the annual PCA true-up accounting understates the power costs that the Company actually incurs on behalf of its customers.

Q. Please describe the Company's proposal to add the costs of a new credit line to the Power Cost Baseline Rate.

A. Mr. Mills' testimony discusses the hedging strategies that the Company utilizes to decrease the volatility and risks associated with power costs. He also explains the credit constraints that give rise to the Company's need for a new credit line to support its wholesale power market hedging transactions. As described in his testimony and in the testimony of Mr. Don Gaines, the costs of such a new credit line depend on the amount of the credit line and the extent to which the line is actually used. This makes it very difficult to project, in advance of a rate year, the costs related to such a credit line or to include the credit line in the Company's cost of capital calculation.

Thus, the Company proposes to track the fees and costs of such a new credit line that are associated with electric portfolio hedging as a part of the PCA Mechanism calculation. PSE would track these fees in accounts separate from other bank fees and interest payments so that the costs would be easily identifiable and could be audited as part of the annual PCA true-up filing. The table presented in Exhibit No. ___(JHS-7C) provides an example of the estimated range of costs for this line of credit at various levels of activity. On a

$200 million credit line, such costs could range from approximately $400,000 to approximately $11 million annually.

The Company is also proposing to track the fees and costs of this new credit line that are associated with core gas portfolio hedging and pass them through as part of the Company's Purchased Gas Adjustment ("PGA") Mechanism, as described in Mr. Karzmar's testimony.

Q. How have these proposed revisions been reflected in the Company's proposed PCA Mechanism text?

A. These proposed changes are reflected in the Proposed New and Revised Terms for the PCA Mechanism, which is Exhibit No. ___(JHS-8C). Because the Commission and stakeholders are already familiar with the current PCA Mechanism and because it has already been applied to three separate annual compliance filings, the Company started with the current PCA text in developing its Proposed New and Revised Terms for the Power Cost Adjustment Mechanism and made as few changes as possible to that document.

The revised sharing bands are incorporated into Section 2.1 of the Proposed New and Revised Terms for the Power Cost Adjustment Mechanism (PCA). In Exhibit A-1, a line was added to provide a place for future interest cost estimates associated with the hedging line of credit. Exhibit B in the PCA Mechanism is changed by adding a line to pick up the costs associated with the line of credit to be used for hedging. Exhibit B is shown for illustrative purposes only and power costs shown on this page are from the PCA 3 compliance filing. As described above, Exhibit E is eliminated under the Company's proposal.

Finally, a new Exhibit H has been added to incorporate into the PCA Mechanism itself the clarification of certain methodologies to be applied in the PCA accounting that were approved by the Commission in the annual compliance filing for PCA Period 1, Docket No. UE-031389.

C. <u>Application of the PCA Mechanism to Adjust the Power Cost Baseline Rate for This Case</u>

Q. Is the Company proposing a Power Cost Baseline Rate in this case consistent with the 2004 general rate case and 2005 PCORC?

A. Yes. The changes that PSE is proposing to the PCA Mechanism, described above, would primarily be applicable in future annual PCA true-ups. Thus, the Company's proposed new Power Cost Baseline Rate has been calculated in the same manner as in the 2004 general rate case and 2005 PCORC. This is shown on Exhibit No. ___(JHS-9C). The proposed new Power Cost Baseline Rate is $59.208 per MWh before revenue sensitive items, compared to the current Power Cost Baseline Rate of $52.409 per MWh that was approved in the 2005 PCORC.

Q. Please describe the Company's request to include costs associated with the new line of credit for hedging activities?

A. That line of credit does not yet exist, and any projection of associated fees and costs is complicated by lack of current information regarding the extent to which the line would actually be used during the rate year. Thus, the Company's new Power Cost Baseline Rate does not include any such costs in this case. Instead, actual costs will be flowed through the monthly PCA calculation and will be included in the costs subject to the new sharing bands. As the Company gains experience with the costs associated with this line of credit, future proceedings may have an estimate for the expected rate year costs.

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

A. The PCA Mechanism makes a distinction between production related 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 proforms those costs back to the test year. The proposed rate year used for these adjustments in this proceeding is January through December 2007. For this proceeding we have used the test year ended September 2005.

In addition to providing the normal power cost restating and pro forma adjustments we have provided proforma adjustments to account for changes to

PSE's ratebase and operating expenses associated with the purchase of the Hopkins Ridge wind project, the Wild Horse wind project and the Baker Lake Relicensing project discussed earlier. These costs are included in the appropriate line items on Exhibit A-1.

Q. Please explain what Exhibit No. ___(JHS-9C) represents.

A. Exhibit No. ___(JHS-9C), page 1, is equivalent to Exhibit A-1 Power Cost Rate set forth in the original PCA Settlement, but has been 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 first page, 7.57%, is the net of tax rate of return being requested by the Company in this proceeding. The test period power costs are allocated, in the same manner as in prior PCA calculations, 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-1 of the current PCA Mechanism, we have divided this result by the test year delivered load to calculate the new Power Cost Baseline Rate of $59.208 per MWH before revenue sensitive items.

Q. Please explain the remaining pages included in Exhibit No. ___(JHS-9C).

A. The remaining pages of this exhibit are equivalent to the Exhibits A-2 through D set forth in the current PCA Mechanism, 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 current PCA Mechanism. As described above, Exhibit E is eliminated under the Company's proposal. However an Exhibit E for the rate period has been prepared and has been provided to other parties in my workpapers.

VI. PSE'S PROPOSALS TO ADDRESS REGULATORY LAG AND ATTRITION

A. Background Regarding Regulatory Lag and Attrition

Q. Would you please describe what is meant by the term "regulatory lag"?

A. The term "regulatory lag" is generally associated with the delay between the time expenses are incurred or ratebase investments are made and the time when the rates to recover these costs actually go into effect. For example, if an historical test year is used to set prospective rates and a regulatory proceeding takes fifteen months to prepare and process, the regulatory lag would be measured as twenty seven months from mid test year to mid rate year or end of test period to end of rate year.

Q. Would you please describe what is meant by the term "attrition"?

A. Attrition is caused when the relationship between revenues and costs varies over time, causing a company's earnings to vary from what was targeted in a rate proceeding.

For example, attrition can occur if an historical test period is used for setting rates for a company that is experiencing considerable growth or replacement of infrastructure and its marginal cost of serving customers is greater than its embedded cost of serving customers.

Q. Would you please provide a specific example?

A. Ms. Sue McLain discusses in her prefiled direct testimony, Exhibit No. ___(SML-1CT), how costs have increased for the Company's gas and electric system infrastructure over the last 30 plus years. Using her example of a 45 foot pole that cost $470 dollars in 1974 and over $2,300 dollars in 2004, the variance in recovery of costs can be fairly easily calculated. The depreciation rate on this type of plant is 2.30%, so the Company's depreciation expense goes from $10.81 to $52.90 when a new pole is installed. At the same time, the return on the plant should go from $17.13 to $294.72 (ignoring deferred tax considerations). Taken together, the total cost recovery requirement goes from $27.94 to $347.62 as shown in Exhibit No. ___(JHS-10). However, after the pole is replaced and continuing until the next rate case is finalized and rates re-set, the Company continues to collect only the $27.94 level of costs in its rates rather than the $347.62 that is needed.

As this example shows, the time period from the in-service date for a particular piece of plant to its retirement date determines the inflationary impact of the replacement and affects the measure of attrition that this plant replacement will have on earnings. Current annual inflation levels need not be high for the costs of such new investments to significantly outpace the costs of the original infrastructure that are embedded in rates.

While the dollar amounts in the above example are small for one pole, the total impact of all of the Company's infrastructure investments over the course of a year or two can be very significant. This is a particular concern for the Company at the present time because of the large and growing capital investments the Company must make in its electric and gas system infrastructure. As discussed by Ms. McLain, the capital expenditures required of the Company for infrastructure replacement and growth will be much higher over the next two years than the capital expenditures the Company has made over the last two years. The increased capital expenditures for electric transmission and distribution for 2006 and 2007 are approximately $157.1 million and $222.8 million, respectively. This is significantly higher than the $90.1 invested in 2003 or the $121.2 million invested in 2004 and is equal to or greater then the $158.6 invested in 2005.

Q. Is there a similar problem with new infrastructure that is installed as opposed to replacements of existing infrastructure?

A. Yes. Where capital costs are being incurred to meet customer growth, it is expected that revenues will grow with the addition of the new customers. However, because rates are currently designed to recover the historical embedded cost of transmission and distribution plant, the new revenues are unlikely to grow at a rate sufficient to cover the new transmission and distribution plant costs that are incurred to serve the new customers. The attrition caused by this difference will not be recovered until the next rate case is finalized and rates reset.

Q. Has this Commission recognized the problems caused by attrition?

A. Yes. For example, in Docket Nos. U-82-10 and U-82-11, *WUTC v. Washington Water Power*, Second Supplemental Order, the Commission stated:

> When the company is experiencing vastly different rates of change in revenues, expenses and ratebase, the problem of earnings attrition occurs. The Commission finds that a refusal to recognize this problem, as demonstrated by the record in this case, would amount to a refusal to allow the company a reasonable opportunity to earn its allowed rate of return.

Q. Are there different ways to address regulatory lag and attrition?

A. Yes. Some of the more common are:

- Pro forma adjustments for known changes that increase a company's revenue requirement;

- Use of test period year-end ratebase rather than average test period ratebase;
- Use of future test years;
- Various types of attrition allowances, including but not limited to allowing future additions to ratebase, trending using selected revenue and cost data and increasing the allowed rate of return; and
- Interim procedures that allow utilities to adjust rates in between general rate proceedings for specific cost increases.

Q. How has this Commission historically addressed attrition?

A. The most common means, applied to some extent in every rate case before the Commission, is the use of pro forma adjustments to test year data under the "known and measurable" standard, as set forth in WAC 480-07-510(3)(b)(ii). While helpful in reducing the extent of attrition that would occur absent such adjustments, this method has generally been restricted to specific types of costs and to time periods that may not extend to the rate year.

The Commission has also approved attrition allowances in the past on a case by case basis. The most common such method approved by the Commission is a procedure that trends revenue and cost data to determine an attrition adjustment that is added to the revenue deficiency in a general rate case filing. This methodology was utilized in several filings during the early to mid 1980's, in which inflation was identified as the primary driver of attrition However, the

Commission has noted that attrition can be caused by a variety of factors, including growth in ratebase, growth in expenses, and changes in demand.[1]

Finally, the Commission has approved interim procedures, such as the Company's PCA Mechanism and PCORC proceedings, that allow utilities to adjust rates in between general rate proceedings to recover commodity costs that are increasing faster than the levels built into rates.

Q. Has this Commission approved any other means of addressing attrition?

A. In 1981 the Commission allowed Washington Water Power Company (Docket U-80-111) to use test year ended ratebase rather than average ratebase, stating:

> It is not a misstatement to say that the weight of authority, both in the administrative and judicial branches, favors average over year-end ratebase on the premise that in normal economic times average ratebase is more realistic and projects more accurately the cost of plant that produces the revenue under investigation. However, there is sizeable and well-recognized authority that in an abnormal and less stable economic climate year-end ratebase may be more appropriate and should be used to balance out the financial problems caused by abnormal and uncertain economy.

The above Docket is the only one that we were able to find in which the Commission has approved year end ratebase, although that method has been proposed in a number of historic rate case filings.

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[1] WUTC v Washington Water Power Company, Docket No., U-83-26, Fifth Supplemental Order, 1984 Wash. UTC LEXIS 69 at *47-49 (Jan. 1984).

We were unable to find any cases in which the Commission has approved use of a fully pro formed and restated future test year.

B. Regulatory Lag and Attrition Should Be Addressed in this Proceeding

Q. Does the Company currently experience regulatory lag and attrition?

A. Yes, particularly with respect to its natural gas service. Although the Company has the PGA Mechanism, this addresses only the potential mismatch between commodity costs built into rates and current market costs. The PGA Mechanism does not address significant regulatory lag and attrition problems associated with the Company's high level of capital investment in natural gas infrastructure that address customer growth, maintenance of its aging system, and increased safety regulations or requirements, as discussed in Ms. McLain's testimony.

Q. Why are these capital investments causing an attrition problem?

A. The problem is caused by the lag between the time when the investments are made and the time when rates reflecting such costs become effective. As discussed earlier, the problem is particularly acute with respect to replacement of PSE's aging infrastructure, because plant put into ratebase twenty to thirty years ago has a much lower average cost then the capital additions which are replacing it. In addition, the Company is making very large and growing capital investments in its gas infrastructure. Mr. Karzmar discusses the impact on the Company's costs to serve its gas customers in more detail in his testimony.

Q. How does the Company propose to address these issues?

A. The Company is proposing a new Depreciation Tracker that would true up revenues for changes in depreciation expense related to natural gas and electric transmission and distribution capital investment, which I describe in greater detail below.

Q. Is the Company requesting an attrition adjustment in this case based on the trended methodology that the Commission has accepted in some historic rate cases?

A. No, the Company believes that the measures PSE is proposing better address regulatory lag and attrition in the Company's current environment. However, for informational purposes, the Company did prepare an analysis consistent with this historic methodology for both its natural gas and electric service. The electric attrition analysis is described in Exhibit No. ___(JHS-11) and Exhibit No. ___(JHS-12), and Mr. Karzmar discusses the natural gas attrition analysis in his Exhibit No. ___(KRK-1T) and Exhibit No. ___(KRK-7).

Q. What was the result of the Company's trended electric attrition study?

A. The estimated electric trended attrition between the test year and the rate year for non-production related costs is an under recovery of approximately $1.7 million net operating income.

Q. How would these results be applied if the Company was requesting an attrition adjustment in this filing based on the trended methodology?

A. If the Company were requesting a traditional attrition adjustment in this case, the $1.7 million net operating income under recovery would be added to the Company's electric revenue requirement net operating income deficiency for this filing.

Q. Did the Company perform any other analysis as a check on the traditional trended attrition analysis?

A. Yes. In addition to the trending of revenues and costs, described in Exhibit No. ___(JHS-11) and Exhibit No. ___(JHS-12), we compared the Company's rate year financial forecast to the trended attrition analysis.

Q. What was the result of this analysis?

A. The financial forecast for electric operations shows an under recovery for net operating income for calendar year 2007 of approximately $42.4 million, a difference of $40.7 million dollars from the trended attrition analysis.

Q. Why is there such a large difference between the trended attrition results and the Company's financial model?

A. One of the assumptions in the trended attrition analysis is that the trends from two historical time periods will be close to the trend between a current test period and the rate year. As discussed above, the capital expenditures required of the Company for infrastructure replacement and growth will be much higher over the next two years than the capital expenditures the Company has made over the last two years. The financial model estimates that electric ratebase will grow to $3,283,470,000 in 2007. The equivalent ratebase from the trended analysis would be $2,952,521,072, which is the sum of (i) ($1,357,008,573, production ratebase, adjusted by the production factor, plus (ii) $1,595,512,499, the trended non-production ratebase. The difference in ratebase is approximately $330.9 million. The net operating income impact of the difference between these two ratebase amounts accounts for $29 million of the $40.7 million difference between the trended attrition analysis and the financial model attrition analysis.

Q. How much of the difference in ratebase growth is attributable to transmission and distribution system growth?

A. Electric transmission and distribution plant in-service is expected to grow by $434 million by December 31, 2007. The average of monthly average 2007 associated with new transmission and distribution plant after September 30, 2005 would be $318.5 million and the actual growth on ratebase would be approximately $155.3 million after deducting for the change in accumulated depreciation and deferred taxes associated with electric transmission and distribution plant. As discussed by Ms. McLain, the increased capital expenditures for electric transmission and distribution for 2006 and 2007 are approximately $157.1 million and $222.8 million, respectively. This is significantly higher than the $90.1 invested in 2003 or the $121.2 million invested in 2004 and is equal to or greater then the $158.6 invested in 2005.

C. PSE's Proposed Depreciation Tracker

1. Overview

Q. Why is the Company proposing a Depreciation Tracker mechanism in this case?

A. The Company's proposed Depreciation Tracker mechanism is designed to directly address a major cause of the attrition that is facing the Company at the present time: the Company's rapidly increasing investment in its electric and natural gas transmission and distributions systems. As described above and in greater detail below, as soon as this new plant is placed in service, the Company must start depreciating it. When the marginal cost of this new plant is greater than the cost of similar plant that is embedded in rates, the resulting increased depreciation expense, until reflected in rates, has a negative impact on earnings. The proposed Depreciation Tracker would permit the Company to recover the costs of this increased depreciation expense.

The Depreciation Tracker addresses recovery of investment in new plant. The Depreciation Tracker does not address the attrition that is caused by lack of recovery *on* the new plant. Such recovery would continue to be forgone until adjustment in a rate caseof the Company's rate base to updated levels. The Depreciation Tracker is a relatively simple, transparent mechanism that can be estimated in advance, trued up to actual after the fact, and will go part of the way toward addressing the attrition the Company is experiencing related to its increasing infrastructure investments.

Q. Please describe the Company's proposed Depreciation Tracker.

A. The Company is proposing that the increased expense associated with growth in depreciation for electric and natural gas transmission and distribution plant investments be recovered using a tracker mechanism. This tracker mechanism would provide for recovery of the Company's investments in transmission and distribution infrastructure through a surcharge to the Company's existing tariff schedules. This surcharge would be based on the incremental depreciation expense of natural gas and electric transmission and distribution investment over and above the depreciation expense reflected in existing rates. The cost recovery takes into consideration the growth in revenues associated with increased load so that there is no "double recovery" with new natural gas and electric transmission and distribution investment. Additional details regarding the proposed Depreciation Tracker are described below, and the proposed tariff schedules for implementing the Depreciation Tracker are presented in the testimonies of Mr. James Heidell and Ms. Janet Phelps.

2. <u>Additional Details Regarding the Attrition Facing the Company Related to Its Transmission and Distribution Infrastructure Investments.</u>

Q. Would you please explain, from an accounting perspective, how new capital investments impact the Company's earnings and plant values?

A. During construction, the costs associated with new utility plant are capitalized on the balance sheet. If the life of the construction project extends beyond a couple of months, the carrying costs ("AFUDC") composed of interest and equity recovery, is credited to the income statement and charged to the capital project. The booking of AFUDC increases interest income on the income statement and increases the cost of the project for the balance sheet. If this were the only thing happening on a utility's books, the impact would be the same as earning the rate of return on the capital invested in construction. A major difference from revenues being increased to cover this construction is that AFUDC earnings have no cash value.

When the new construction is completed and closed to "in-service", the AFUDC stops and depreciation expense commences. The impact of this change is to decrease interest income and increase operating expense. This change in the financial statements is a major cause of earnings attrition when construction expenditures are increasing faster than supporting revenues. Until rates can be reset, there is a lag and growing attrition between the time the investment is made and the time the investment is reflected in new rates. This results in an earnings lag for (1) recovering *on* the investment (the interest and equity costs), (2) recovery *of* the investment (depreciation expense) and (3) recovery of incremental O&M costs related to the new plant.

Q. Why must the Company start depreciating plant once it goes into service?

A. Depreciation is the equitable allocation of the cost of an asset over its useful life and is required by Generally Accepted Accounting Principals and FERC accounting instructions, when an asset is put in service. Accounting Research Bulletin 43, paragraph 5, states:

> The cost of a productive facility is one of the costs of the services it renders during its useful economic life. Generally accepted

> accounting principles require that this cost be spread over the expected useful life of the facility in such a way as to allocate it as equitable as possible to the periods during which services are obtained from the use of the facility.

Statement of Concepts Number 5, paragraph 86, states:

> Consumption of economic benefits during a period may be recognized either directly or by relating it to revenues recognized during the period:
>
> a. Some expenses, such as cost of goods sold, are matched with revenues—they are recognized upon recognition of revenues that result directly and jointly from the same transactions or other events as the expenses.
>
> b. Many expenses, such as selling and administrative salaries, are recognized during the period in which cash is spent or liabilities are incurred for goods and services that are used up either simultaneously with acquisition or soon after.
>
> c. Some expenses, such as depreciation and insurance, are allocated by systematic and rational procedures to the periods during which the related assets are expected to provide benefits."

FERC accounting instructions reflect these same requirements. General Instruction 22 states:

> A. *Method*. Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.
>
> B. *Service lives*. Estimated useful service lives of depreciable property must be supported by engineering, economic, or other depreciation studies.

> C. *Rate.* Utilities must use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property to the service life of the property. . . .

FERC also provides the following definition of service life.

> 35. *Service life* means the time between the date electric plant is includible in electric plant in service, or electric plant leased to others, and the date of its retirement. . . .

Electric and Gas plant is includible in plant in service when construction and testing is completed as stated in the instructions for Account 107, Construction Work in Progress.

Q. Could a utility defer booking depreciation on the income statement if a State utility commission ordered it to defer depreciation until plant is included in rates?

A. Not directly. FAS 71, Accounting for the Effects of Certain Types of Regulation, does allow a utility to defer an incurred cost if there is reasonable assurance that future revenues would cover that cost. An incurred cost is defined as a cost arising from cash paid out for an asset or service that would normally be charged to expense. As depreciation is the allocation of a previously capitalized cost over its useful economic life, it would be argued that this is not the type of incurred cost contemplated under FAS 71.

For example, in 1986 FERC required Puget Sound Power & Light Co. ("Puget") to record depreciation on Colstrip Common Plant from the in service date of Colstrip Unit 3 even though the Washington Commission had ordered the Company to keep this Common Plant in CWIP (Cause No. UE-83-54) until Colstrip Unit 4 was in service. Puget was required to record the depreciation, and other expenses, associated with the Common Plant as if the plant had been put in service at the same time as Colstrip Unit 3.

The Washington Commission did ultimately allow Puget to treat the depreciation, property taxes and carrying costs that were or would have been booked on this Common Plant as a regulatory asset. These costs could only be recognized as a regulatory asset upon the Washington Commission Order authorizing the deferral and were not allowed to be recorded in the capital or depreciation accounts.

3. <u>Details Regarding PSE's Proposed Depreciation Tracker</u>

Q. Please explain how the Company proposes to calculate the Depreciation Tracker?

A. The Company proposes to calculate the change in revenue deficiency for depreciation expense based on the unit cost recovery for this item that was allowed in the Company's most recent general rate case. If the Depreciation Tracker is approved, this unit cost would be adjusted each year to reflect the additional costs recovered in rates due to implementation of the surcharge.

Basing recovery on the unit cost associated with depreciation expense is similar to the calculation the Company currently utilizes for power cost recovery in its PCA Mechanism. The unit cost would be determined by dividing the depreciation expense allowed for rate recovery by the delivered load used for determining rate spread from the Company's most recently approved revenue adjustment.

For example, in this general rate case filing, the transmission and distribution depreciation expense is approximately $71.4 million for electric (this is net of the transmission depreciation expense included in the PCA Mechanism and transmission and depreciation expense allocated to Schedule 40) and $50.3 million for natural gas (this is net of the rental depreciation expense which would be excluded from the tracker). Dividing these amounts by the delivered load for the different energy services yields a cost recovery rate of $.003268 per kWh for the electric customers and $.048436 per therm for the natural gas customers.

The Company proposal is to file by November 15 of each year for a change in the Depreciation Tracker surcharge rider that would take effect January 1 of the next year. To calculate the surcharge amount, the Company would first determine the transmission and distribution depreciation expense that is forecast to be recovered in rates during the next calendar year by multiplying the unit cost rates that are then in effect by the forecast delivered load for the next calendar year. This forecast recovery amount would then be compared to the Company's forecast of depreciation expense associated with transmission and distribution. The difference between the forecasted recovery rate, and the forecasted depreciation expense would be the rate adjustment for each energy service. This calculation is presented below.

Line No.	Depreciation in Test Year	9/30/2005	2007	2007 Tracker
1	Electric			
2	Transmission	2,162,707	2,154,681	
3	Distribution	69,255,510	77,619,411	
4		71,418,217		79,774,092
5	Delivered Load (MWH)	21,853,035	22,107,507	72,249,861
6	Unit Cost ($/KWh)	0.003268		
7	Adjustment			7,524,231
8			Conversion	0.9549744
			Revenue Def.	7,878,988
9	Gas			
10	Transmission	2,911,749	3,752,000	
11	Distribution	47,386,339	57,900,661	
12		50,298,088		61,652,661
13	Delivered Load (thousand therms)	1,038,451	1,057,971	51,243,553
14	Unit Cost ($/therm)	0.048436		
15	Adjustment			10,409,108
			Conversion	0.9563082
16			Revenue Def.	10,884,680
17			Total	18,763,667

The column labeled 9/30/2005 shows the calculation used to determine the unit costs associated with transmission and distribution depreciation expense for the electric and natural gas services. For this calculation, electric transmission depreciation expense is reduced by the transmission expense that is included in the PCA Baseline Rate because it is recovered under the provisions of the PCA mechanism. Electric depreciation is further reduced by the transmission and distribution expense recovered under Schedule 40 for the reasons discussed by Mr. Heidell in his direct testimony. Natural gas depreciation expense is reduced by the depreciation expense allocated to rentals as this depreciation expense is not recovered on volumes. After these adjustments are taken into consideration, the resulting depreciation expense for the test year is divided by the delivered load to determine a unit cost per kWh or therm. The unit costs for the different services are then multiplied by the expected delivered load in the rate year. This amount of depreciation expense, $72.2 million for electric and $51.2 million for gas, is then compared to the forecast depreciation expense in the rate year.

Using this calculation, the electric tracker rates would be adjusted to recover a revenue deficiency of $7.9 million and natural gas tracker rates would be adjusted to recover a revenue deficiency of $10.9 million after adjusting for revenue sensitive items.

Q. How would the Company allocate the revenue deficiency to the different rate schedules?

A. The adjustments under this tracker would be allocated to each of the customer classes based on the allocation of transmission and depreciation from the current cost of service, as described in the testimony of Mr. James Heidell and Ms. Janet Phelps. The allocated amount would then be spread on an equal cents per kWh or therm.

Q. Would there be any true up of these forecasts to actual?

A. For each November filing, except the first filing which is included in this general rate case, the Company would calculate the difference between (i) the forecast of depreciation recovery and depreciation expense amounts and (ii) the actual depreciation recovery and depreciation expense amounts based on actual loads/therms and depreciation expense through September of a given year and a three month estimate for the remaining portion of the year. The three month estimate would be trued up to actual in the next year's calculation and any correction required would be included in the next year's adjustment. If the difference between the actual depreciation and depreciation expense recovered under the tracker is greater than $.5 million, plus or minus, for either electric or natural gas, it is proposed that the difference be included in the next year's tracker calculation. The Company is proposing that there would be no adjustment for differences of less than $.5 million due to the relatively minor impact on rates resulting from such a difference; however, the adjustment could be made for all amounts that deviate from the estimate if the Commission prefers.

Q. Will this Depreciation Tracker eliminate earnings attrition for the Company associated with its infrastructure investments?

A. Partially. The Depreciation Tracker will allow the Company to recover its investment in new transmission and distribution facilities more quickly than under current rate recovery mechanisms that are in place. It will not eliminate all earnings attrition associated with infrastructure investments as this mechanism does not address recovery *on* the investment or the other costs, such as property taxes and incremental maintenance, associated with this type of property. The Company will still be at risk for attrition in this type of cost recovery.

Q. Why is the Company proposing a limited mechanism to address these issues?

A. The Company is proposing the Depreciation Tracker at this time because it is a relatively simple, transparent mechanism that can be estimated in advance, trued up to actual after the fact, and will go part of the way toward addressing the financial pressures the Company is experiencing related to its increasing infrastructure investments.

Q. How would the Company propose to calculate the depreciation tracker for natural gas if the Commission approves the decoupling mechanism?

A. The projection of the depreciation expense revenue deficiency would be done in the same manner as discussed above. An average rate per therm would be used and multiplied by the therms in the rate year to estimate the revenue recovery of the depreciation expense recovered in rates.

The true up for actual revenues collected versus what was estimated would change. To calculate the amount of revenues collected we would first take the average depreciation rate per decoupled customers for the test year plus the average depreciation rate per decoupled customer in the tracker and multiply it times the number of decoupled customers in the collection period. The second step would be to take the average depreciation expense revenue requirement embedded in the non-decoupled customers' rate per therm plus the average depreciation rate per therm allocated to these customers in the tracker and multiply it times the non-decoupled customers' load in the collection period. The sum of these two calculations would be the amount of depreciation collected from customers and would be the amount compared to actual gas transmission and distribution depreciation expense to see of any adjustment is required.

VII. PSE'S CHELAN CONTRACT ACCOUNTING PETITION

Q. Are there any other regulatory issues related to this filing that have not been previously addressed in your testimony?

A. Yes. In his direct testimony, Exhibit No. ___(EMM-1HCT), Mr. Markell discusses the purchased power agreement with Chelan County Public Utility District No. 1 ("Chelan Contract") and its requirement that the Company make an up-front capacity reservation payment in the amount of $89 million. As Mr. Markell states, the Company will be filing an Accounting Petition with respect to this payment.

In the Accounting Petition, the Company will request that the Commission approve setting up a regulatory asset to defer the $89 million upfront payment and allow the Company to accrue interest on this regulatory asset at its net of tax rate of return. To the extent the Commission considers this issue in the context of this general rate case, the Company is requesting that the Commission confirm that this deferral and amortization of this contract payment is the appropriate accounting for financial and ratemaking purposes.

Q. Why will the Company request this accounting for financial and ratemaking purposes?

A. The reason that the Company will propose this accounting is that by deferring the payment and carrying costs for the $89 million until power is received, it insures that the customer receiving the benefit of the contract pays for the costs of the contract. In addition, by amortizing the $89 million, with carrying costs, over the life of the contract, a major up-front cost of obtaining the contract is allocated equitably over the life of the contract. As discussed by Mr. Elsea, Exhibit No. ___(WJE-1HCT), the deferral of this payment, accrual of interest at the net of tax rate of return and the resulting amortization of the regulatory asset plus its carrying costs over the life of the contract, were taken into consideration when determining the levelized cost for the Chelan Contract.

VIII. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

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