EXHIBIT NO. ___(JHS-1CT)
DOCKET NO. UE-07___/UG-07___
2007 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-07____** **Docket No. UG-07____**

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
JOHN H. STORY
ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED VERSION

DECEMBER 3, 2007

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF JOHN H. STORY

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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, Inc. ("PSE" or the "Company"). 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 present the electric results of operations, electric revenue deficiency and PSE'S update on the PCORC Collaborative that the Commission directed the parties to convene in Docket UE- 070565.

I describe the different allocation methods used to allocate 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 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 deficiency. I also present the exhibits for the PCA Mechanism that are updated for changes to the Base Rate for pro forma and restating adjustments to power costs.

Based upon the adjusted test period revenues of $1,836,866,925 for sales to customers, the total requested electric general rate case revenue deficiency is $174,819,117. Firm Resale customers are allocated $336,605 of this deficiency and the retail sales revenue deficiency is $174,482,512, which represents an average 9.50% increase. This increase does not reflect an additional Production Tax Credit associated with the new turbines being constructed at the Hopkins Ridge Wind Project.

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 3.01 of Exhibit No. ___(JHS-3) presents a comparison between the unadjusted electric income statement for 9/30/2005, the test year for Docket No. UE-060266 et al. (the "2006 general rate case") and the unadjusted electric income statement for 9/30/2007, the test year for this general rate case filing. Page 3.02 of Exhibit No. ___(JHS-3) presents the combined balance sheet for the same time periods, and page 3.03 of Exhibit No. ___(JHS-3) presents the ratebase calculation for the current test year prior to any pro forma and restating adjustments. Mr. Karl R. 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 one exception. The working capital calculation has been updated to reflect the allocation of working capital between electric, gas and nonutility functions. Mr. Karzmar explains this change in his testimony.

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 electric operating investment, which is earning a return, or is excluded from earning a return, is deducted. A similar deduction is made for natural gas operating investment and non-operating assets plus plant not in service. The result is total working capital for total investments. The electric portion of working capital is calculated by taking the relationship of the total working capital to total investments times the electric operating investment. An adjustment is also made to the electric working capital for Construction Work in Progress ("CWIP") using the same methodology that has been approved in prior proceedings. The electric working capital calculation is shown in Exhibit No. ___(JHS-3), page 3.04, and adds $95,493,209 to electric ratebase.

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

A. The final page of Exhibit No. ___(JHS-3) 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; and (5) direct labor.

III. CAUSES OF THE REVENUE DEFICIENCY

Q. Would you please describe the causes of the revenue deficiency?

A. Yes. To determine the major causes of the changes between two regulatory filings the Company uses a unit analysis. This analysis is simply the major categories of the income statement or ratebase that is determined for each of the regulatory periods divided by the delivered load for that period. This calculation determines the major categories' unit cost for that particular period. The prior period that is used in this calculation has also been adjusted for the restating and pro forma adjustments that were allowed in the most recent prior period docket impacting a cost element, for example, a PCORC. The difference between the current period and prior period unit costs are then multiplied by the delivered load for the current regulatory period. This product determines how much that major category has increased or decreased in cost since the last regulatory period taking into consideration load growth.

Exhibit No. ___(JHS-6), page 2, shows the calculation for the difference between the adjusted test period for this general rate filing, as determined in Exhibit No. ___(JHS-4), and the 2006 general rate case revenue requirement adjusted for the change in power costs and revenues as determined in the Final Order of Docket No. UE-070565, the 2007 PCORC filing that increased electric revenues effective September 1, 2007. Page 1 of this exhibit shows the calculation of the difference between the unit costs between the two periods described above and the increase or decrease in cost since the last regulatory period taking into consideration load growth.

Based on this calculation, cost increases include the following:

(i) $55.1 million for power cost expenses related to the rate year in this proceeding;

(ii) $10.7 million in other operating expenses including expenses for production plant related to the addition of new resources;

(iii) $8.5 in transmission and distribution expenses which is partially explained by increased tree trimming and storm damage expense;

(iv) $19.9 million in amortization of property losses which includes storm damage amortization related to the December 2006 storms;

(v) Other O&M expenses have increased $9.5 million due to salaries, outside services and insurance;

(vi) Depreciation expense has increased $12.8 million, of which approximately $8 million is related to a new depreciation study which I discuss later in my testimony;

(vii) Amortization expense has increased approximately $6.8 million due to capital additions for software closing since the last general rate case; and

(viii) The change in ratebase increases the revenue requirement by $38.0 million, of which approximately $12.2 million is related to the requested change in rate of return.

Q. What are the major changes in ratebase since the last proceeding?

A. The majority of the revenue requirement change associated with ratebase is the addition of plant to Transmission and Distribution. In the last general rate case filing the electric ratebase was approximately $2,977.3 million and in this proceeding it is being filed at $3,305.1 million, which is an increase of $327.8 million. Transmission and Distribution plant, net of accumulated depreciation, amounts to $246.6 million of that difference. Production plant has also increased by $72.9 million, net of accumulated depreciation. Working capital is calculated at a $95.5 million dollar increase, which is related to the deferrals associated with storm damage discussed later in my testimony. These increases in ratebase are offset by the growth in deferred taxes and the increase in customer advances due to increased residential construction activity.

IV. ELECTRIC PROFORMA AND RESTATING ADJUSTMENTS

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

A. Exhibit No. ___(JHS-4) presents the impact of each of the pro forma and restating adjustments being made to the September 30, 2007 operating income statement and balance sheet. The first page of Exhibit No. ___(JHS-4), Summary page, presents the unadjusted operating electric income statement and Average-of-the-Monthly-Averages ratebase for the Company as of September 30, 2007 (the test year) in the column labeled Actual Results of Operation. The various line items are then adjusted by the summarized pro forma 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 Exhibit No. ___(JHS-4) 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 pro forma and restating adjustments. The first column of numbers, on page 4-A, is the unadjusted net operating income for the year ended September 30, 2007 and the unadjusted ratebase for the same period. Each column to the right of the first column represents a pro forma 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, is restating 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 and the temperature normalized GPI, (138,730) MWH, 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. The prefiled direct testimony of Mr. David W. Hoff, Exhibit No. ___(DWH-1T), discusses the Company's weather normalization methodology and the allocation to the rate classes based on the proposed rate class level weather normalization methodology. In general, 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 colder than normal requiring an adjustment of net operating income to bring revenues down to what is estimated would have occurred under normal conditions. The temperature load adjustment decreases actual GPI by 138,730 MWH, or 129,434 MWH when adjusted for line losses. After allocation to the different customer classes, this results in a decrease to net operating income of $7,499,730.

4.02 <u>General Revenues</u>

This is a pro forma and restating adjustment, shown on Exhibit No. ___(JHS-4), page 4-A, column 4.02, which adjusts the test year to reflect the revenue that would have been collected during the test year if the revenues from the 2006 general rate case and from PSE's 2007 power cost only rate case, Docket UE-070565 ("2007 PCORC"), had been in effect during the entire test period. The revenues from PCORC Docket No. 050870 during the test period are removed as this tariff was set to zero and the revenues are now collected as part of the 2006 general rate case and are included in that adjustment on line 3.

This adjustment also adds back to revenues the Production Tax Credit associated with the wind plants, as this credit is not a general tariff. The tax deduction associated with the Production Tax Credit is removed in the Federal Income Tax calculation on Page 4.04.

The reduction of revenues shown on line 12 is the revenue impact of a customer moving to Schedule 49 from Schedule 31 and additional load for Schedule 40 from various schedules.

Pole attachment revenues are trued up for rate changes and contract changes during the test period on line 23, which reduces revenues by $426,324. The other adjustments to revenues are related to miscellaneous out-of-period price changes for all sales customers.

Net operating income is increased by $49,910,343 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-6). The hedging costs associated with the new line of credit for hedging that was approved in the Company's last general rate case are also shown on this adjustment and add $285,289 to total power costs. The line of credit costs represent the electric services portion of the fees associated with having the line of credit. Rate year power costs have been adjusted to test year power cost levels by a "production factor" discussed later in my testimony.

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

A. Net operating income is decreased by $50,814,456 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-7C), discussed later in my testimony, adjusts the power cost adjustment ("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 2006 general rate case compliance filing. Exhibit No. ___(JHS-7C) also presents the updates for the other schedules used in the PCA mechanism.

Q. Please continue describing the restating and pro forma 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 ending September 30, 2007. Taxable income is shown as a loss on this adjustment as the electric income includes the current deduction associated with the storm losses during the latter part of 2006 and beginning of 2007. The tax benefits of these losses have been normalized and are provided to the customer in the restating Storm Adjustment. The effect of this adjustment, shown on Exhibit No. ___(JHS-4), page 4-A, column 4.04, is to decrease net operating income by $12,165,039.

4.05 <u>Tax Benefit of Pro Forma Interest</u>

This pro forma adjustment, shown on Exhibit No. ___(JHS-4), page 4-A, column 4.05, uses a ratebase method for calculating the tax benefit of pro forma 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 $2,754,228.

4.06 <u>Hopkins Ridge Wind Infill Project</u>

Q. What is the Hopkins Ridge Wind Infill Project?

A. The Hopkins Ridge Wind Infill Project is a 7.2 MW expansion of the existing 149.4 MW Hopkins Ridge Wind Project located in Dayton, WA. The infill project will install an additional four 1.8 MW Vestas V80 turbines that were included in the original turbine layout of the 149.4 MW Hopkins Ridge Wind Project. Please see the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), for a discussion of this project.

Q. Please explain how the ratebase addition associated with this project was calculated for rate purposes.

A. The estimated acquisition price less the accumulated depreciation and deferred taxes through the October 2009 time period is the amount that PSE used to calculate the investment for the Hopkins Ridge Wind Infill Project. The elements of this calculation are described below.

Construction is projected to be completed July 2008. For the rate year costs, the Company assumed that the construction costs will be final prior to November 2008 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. PSE 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 during the course of these proceedings.

To calculate the depreciation expense, PSE used the currently approved depreciation rate of 4% through October 2008 and then changed the depreciation rate to 4.24%, which is the depreciation rate calculated in the new depreciation study discussed later. The depreciation expense was accrued monthly and 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.

For the Hopkins Ridge Wind Infill Project, the deferred tax calculation is based on five-year tax depreciation. The Hopkins Ridge Wind Infill Project will be added to plant in the third quarter of 2008, so the Company has used the half year convention in calculating the tax depreciation and the deferred tax benefit for the first year of operation.

Depreciation expense shown on line 17 of this adjustment is described above and the property insurance and property taxes are the estimated rate year costs for this new plant addition.

During construction of the Hopkins Ridge Wind Infill Project, a settlement was reached with Blue Sky Wind, LLC about the impact of a wind farm that was constructed near the Hopkins Ridge Wind Project. *See* Exhibit No. ___(RG-1HCT). The settlement amount, [redacted], was treated as a credit against the invoiced construction amounts for the infill project for tracking convenience; however, the dollars associated with this settlement are actually related to future power costs. For purposes of this calculation the credit to the plant construction invoices were removed and set up as a liability. It is proposed that this liability be amortized over two years as a credit to power costs and is shown on line 23 of this adjustment.

These proforma adjustments increase ratebase by $10,325,850 and increase net operating income by $540,198.

4.07 <u>Wild Horse Wind Project</u>

This restating adjustment presents the ratebase and operating expenses associated with the Wild Horse Wind Project. The plant balance, shown on line 2 of this adjustment, is the adjusted test year plant cost for the Wild Horse Wind Project, $370,743,821. This adjustment is necessary as the Wild Horse Wind Project was not put in-service until December 2006 and the historical test year numbers do not reflect the total cost of the project.

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

A. To calculate the investment for the Wild Horse Wind Project, PSE started with the acquisition price less the accumulated depreciation and deferred taxes as of September 2007. Because the plant was in the test period for only 10 months, the monthly depreciation expense as of September 2007 was added to accumulated depreciation as if the plant were in service for three additional months. Deferred taxes were adjusted in the same manner. This monthly book depreciation is based on depreciating this asset over 25 years, which is a 4% depreciation rate. This plant was not included in the new depreciation study and the rate used is the same rate as used in the 2007 PCORC filing.

The Company assumed these adjusted test period costs were equal to the total investment costs. Using this amount, PSE calculated the average of the monthly average plant balance, accumulated depreciation and deferred taxes.

The Wild Horse Wind Project has another deferred tax associated with a timing difference for the project royalty payments. 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, PSE has treated this as a cost of producing power and takes a current tax deduction. This timing difference creates a tax receivable, which has been added to the ratebase calculation. The amount of ratebase increase associated with this item is $338,748 for the test year.

The total of all the adjustments described above increases ratebase by $64,190,026.

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Q. Please explain the other costs associated with the Wild Horse Wind Project on Exhibit No. ___(JHS-4) at page 4.07.

A. The calculation of depreciation expense shown on line 10 is explained above. The production costs associated with the Wild Horse Wind Project are included in the power cost adjustment and supported by Mr. Mills' workpapers. Property taxes and insurance were not identified separately for this project as they are included in the production plant values used in the adjustments for Property Taxes, page 4.15 and Property and Liability Insurance, page 4.23.

The impact of the additional depreciation expense is to decrease net operating income by $2,108,303.

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 2.0 cents per kilowatt hour for wind generation and may be adjusted over time due to inflation. 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, 2008. The use of the credit is restricted in that it can only be used to reduce 25% of a company's current taxes payable to the greater of (a) 25% of the company's tax payable before considering the credit or (b) the level of alternative minimum tax. However, unused credits can be carried forward for up to 20 years.

Q. Does either the Hopkins Ridge Wind Infill Project or the Wild Horse Wind Project adjustment include the PTC associated with their generation?

A. No. PTCs are passed through to the customers on a separate tracker that is adjusted and filed in October of each year. This PTC tracker is forward-looking in that it includes the estimated PTCs that will be earned in the next year and is then trued up to what was actually earned in subsequent filings.

4.08 Goldendale Generating Station

The Goldendale Generating Station is a 277 MW natural gas-fired combined cycle generating facility located on an approximately 42 acre site within the Goldendale Industrial Park and the City of Goldendale, Washington. The Goldendale Generating Station was purchased in February 2007 and approved in the Company's 2007 PCORC filing, Docket No. UE-070565. This pro forma and restating adjustment includes the estimated cost of Goldendale Generating Station as of the rate year, November 2008 through October 2009, taking into consideration the original purchase price, the retirement of certain plant items related to the turbine failure and rebuild. *See* Exhibit No. ___(RG-1HCT).

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 October 2009 time period is the amount that PSE used to calculate the investment for the Goldendale Generating Station. The elements of this calculation are described below.

For the rate year costs, PSE assumed that the plant costs as of September 2007 plus estimated activity for October 2007 were equal to the total capital costs. These costs include the retirement of units of property associated with the turbine failure and the replacement costs of these parts. Using this amount, the Company calculated the average of the monthly average plant balance for the rate period. The Company also calculated the accumulated depreciation by depreciating this plant through October 2008 using the current depreciation rate, 1.39%, and then using the new proposed rate depreciation rate, 1.55%. The deferred tax balance was also calculated through the rate year. *See* Exhibit No. ___(WJE-1HCT).

As with the Hopkins Ridge Wind Infill Project, 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). For the Goldendale Generating Station, the deferred tax calculation is based on twenty-year tax depreciation.

The resulting monthly accumulated depreciation and deferred taxes were then averaged for the rate year in the same manner as the plant cost. An additional deferred tax balance is also deducted from ratebase and this is the deferred taxes associated with the current tax deduction for the plant investment that was retired because of the turbine failure.

These adjustments increase ratebase by $48,370,961.

Q. Please describe the operating expense adjustments.

A. Rate year depreciation expense was described above. As this property was also in the depreciation study discussed later in my testimony, a deduction for the Goldendale Generating Station depreciation expense included in the Depreciation Adjustment, page 4.33 of Exhibit No. ___(JHS-4), is also shown on line 10 of this adjustment. Property insurance premiums are based on estimated premiums, which would be effective through March 2009. The property taxes reflect the estimated payment of taxes for the November 2008 through October 2009 time period or rate year. These taxes are expected to decrease from the amount of taxes recorded during the test year for this project as the tax assessment changes from locally assessed to centrally assessed because of the PSE purchase. The operating and fuel costs for the Goldendale Generating Station are included in the Power Cost Adjustment, page 4.03, and are supported by the prefiled direct testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT), and corresponding exhibits and workpapers thereto.

The impact of the operating expenses presented on this adjustment is to decrease net operating income by $1,033,352.

4.09 Sumas Cogeneration Station

The Sumas Cogeneration Station is an approximately 125 MW natural gas-fired combined cycle generating facility located on an approximately 6-acre site within the City of Sumas, Washington. Please see the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), for a discussion of the purchase price and associated costs of the Sumas Cogeneration Station. Although the contract for this acquisition has not yet been executed, the parties have reached agreement on the purchase price. As noted by Mr. Garratt, a supplemental filing will be made, as necessary, once the contract has been executed.

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

A. The estimated acquisition price as of July 2008 less the accumulated depreciation and deferred taxes through the October 2009 time period is the amount that PSE used to calculate the investment for the Sumas Cogeneration Station. The total ratebase addition includes the purchase price, capitalized transaction costs, due diligence and permits and capitalized property taxes that will be paid in 2009 but are related to the months in 2008 prior to the purchase. As this plant had previously been devoted to public use, there is also a negative acquisition adjustment associated with the accounting entries described above. In addition to these costs there are costs associated with capital improvements, such as computer equipment, plant security and facility improvements. A detail of these costs has been provided in the accounting workpapers due to the highly confidential and confidential nature of some of the costs listed above.

For determining the impact on ratebase, the Company used the total of the above costs as being booked in June 2008 and depreciated these costs out through the rate year. PSE calculated the accumulated depreciation by depreciating this plant through October 2009 using a depreciation rate of 1.74%, which is based on a retirement date of July 2023, the date used by Property Accounting as the retirement date for this plant. This date was determined by adding 15 years to the purchase date, which is the life used by Mr. Elsea in determining the economic value of the Sumas Cogeneration Station.

As with the Hopkins Ridge Wind Infill Project, 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). For the Sumas Cogeneration Station, the deferred tax calculation is based on a combined cycle generating plant twenty-year tax depreciation.

The resulting plant investment, monthly-accumulated depreciation and deferred taxes were then averaged for the rate year. These proforma adjustments increase ratebase by $24,744,721.

Q. Please describe the operating expense adjustments.

A. Depreciation expense is described above. Property insurance premiums and property taxes are estimates for the rate year and provided by Mr. Garratt from the economic analysis of this project. Operating expenses for the Sumas Cogeneration Station are included in the Power Cost Adjustment, approximately $3.7 million, and are discussed by Mr. Mills and Mr. Garratt.

The impact of the operating expenses presented on this proforma adjustment is to decrease net operating income by $1,540,690.

4.10 Whitehorn Generating Station

The Whitehorn Generating Station consists of two GE MS7001E peaking units with a rated capacity of 75 MW each. The units were installed in the early 1980's and were originally acquired through a financing lease with Public Service Resources Corporation ("PSRC"). The facility is located in the northwest corner of Whatcom County two miles from Birch Bay and adjacent to the BP Cherry Point Refinery. Please see the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), for a discussion of the Whitehorn Generating Station.

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

A. The estimated acquisition price less the accumulated depreciation and deferred taxes from the purchase date through the October 2009 time period is the amount that PSE has used to calculate the investment for the Whitehorn Generating Station. As this plant had previously been devoted to public use there is a positive acquisition adjustment associated with the accounting entries recording this purchase. Accordingly, the total ratebase addition includes the seller's original gross plant and accumulated depreciation as well as the purchase price and acquisition adjustment. A detail of these costs has been provided in the accounting workpapers due to the confidential nature of some of the costs listed above.

For determining the impact on ratebase, PSE used the total of the above costs as being booked in February 2009 and depreciated these costs through the end of the rate year. PSE calculated the accumulated depreciation by depreciating this plant using a depreciation rate of 2.85%, which is based on a retirement date of July 2016, the date used by Property Accounting as the retirement date for this plant. For the amortization of the acquisition adjustment, the Company used a 13.48% rate, which is also based on recovering the costs by July 2016. This date corresponds to the life used by Mr. Elsea in determining the economic value of the Whitehorn Generating Station.

As with the Hopkins Ridge Wind Infill Project, 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). For the Whitehorn Generating Station, the deferred tax calculation is based on a fifteen-year tax depreciation.

The resulting plant investment, monthly-accumulated depreciation and deferred taxes were then averaged for the rate year. These adjustments increase ratebase by $15,270,982.

Q. Please describe the operating expense adjustments.

A. Depreciation and amortization expense are described above. Property insurance premiums and property taxes are not identified separately for the Whitehorn Generating Station as this property was considered a capital lease during the test year. As a capital lease this property would have been included in the property tax assessment and insured plant during the test year therefore these expenses are included in the Property Tax and Insurance adjustments. Operating expenses of approximately $435,000 for the Whitehorn Generating Station are included in the Power Cost Adjustment page 4.03 and are supported by the prefiled direct testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT), and corresponding exhibits and workpapers thereto.

The impact of the operating expenses presented on this proforma adjustment is to decrease net operating income by $1,481,961.

4.11 <u>Baker Hydroelectric Project Relicensing</u>

This pro forma adjustment moves the licensing costs associated with the Baker Hydroelectric Project relicensing from Construction Work in Progress ("CWIP") to ratebase and the associated amortization expense. The license issuance has been delayed longer than the Company expected due to appeals of various

Department of Ecology determinations relating to the project. As discussed by Ms. Kimberly J. Harris, Exhibit No. ___(KJH-1T), those appeals have been settled and the license is now expected to be issued by the third quarter of 2008.

For calculating the impact on ratebase, the Company assumed the license would be granted in July of 2008. The ratebase amount used is the actual balance in CWIP as of September 30, 2007 plus an estimate of the allowance for funds used during construction ("AFUDC") from October 2007 through July 2008 on the September 2007 CWIP balance. Using that balance, PSE calculated the amortization through the end of the rate year using the amortization rate of 2.22%, which is equivalent to a 45 year life, which is the anticipated license term that will be granted by the FERC. Accumulated amortization was determined by taking the AMA of the accumulated amortization calculated during the rate year. Additional operating expenses associated with the license have been included in the PCA are discussed in the prefiled direct testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT), and corresponding exhibits and workpapers thereto.

This adjustment increases ratebase by $32,595,386 and decreases net operating income by $479,706.

4.12 <u>Pass Through Revenues and Expenses</u>

This is a restating adjustment which removes from operating revenues all rate schedules that are a direct pass through of specifically identified costs or credits to customers, such as the conservation rider, municipal taxes, the low income program, the Residential Exchange Credit provided by the Bonneville Power Administration and green power. The associated expense that is recorded in the test year for these direct pass through tariffs is also removed in this adjustment. The portion of the green power program recorded in power costs has been included in the power costs page 4.03, and is supported by the prefiled direct testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT), and his corresponding exhibits and workpapers. Additionally, the revenues associated with the Production Tax Credit are removed in the Revenue and Expense adjustment, page 4.02 and the associated expense is removed in the FIT adjustment, page 4.04, as discussed above.

The net impact of this adjustment is to lower net income by $976,447.

4.13 <u>Bad Debts</u>

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. This is the same method originally proposed and approved by the Commission in PSE’s 2004 general rate case.

Each of the five years bad debt expense rate is calculated on the twelve months ending September 30 so that they are consistent with the test year in this case. The bad debt percentage for a given year is calculated by taking the actual writeoffs 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 is a decrease to net operating income of $349,580.

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

This restating and pro forma adjustment, adjusts the test year for several different items.

(a) <u>Adjustments to Operating Income</u>

Restating and pro forma adjustment 4.14 adjusts the test year for the following operating income items.

1. <u>Amortization of Deferred Taxes on Indirect Overheads Regulatory Asset (WUTC Docket No. UE-051527)</u> – In prior years the Company had taken a deduction for certain general overhead costs associated with construction, which created a deferred tax balance. The IRS then changed the method of deduction for these costs and required any utility that had previously deducted these items to reverse the deductions over the 2005

and 2006 tax years. In Docket No. UE-051527, the Company was authorized 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. Because the balance in the regulatory asset will be fully amortized by the rate year, this restating adjustment removes $1,470,386 of amortization of the carrying costs in the regulatory asset from the test period.

2. <u>Amortization of Interest associated with Deferral of Unrecovered Residential Exchange Benefits Credited to Customers (WUTC Docket No. UE-071024)</u> – The United States Court of Appeals for the Ninth Circuit (the "Ninth Circuit") on May 3, 2007, in *Golden Northwest Aluminum v. Bonneville Power Administration*, No. 03-73426 ("*Golden Northwest*"), and *Portland General Electric Company v. Bonneville Power Administration*, No. 01-70003 *("PGE")*, concluded that certain Bonneville Power Administration ("BPA") actions in entering residential exchange settlements with the region's investor-owned utilities were not in accordance with law. On May 21, 2007, BPA notified the region's investor-owned utilities that it would immediately suspend payments under the challenged BPA agreements pending final decisions by the Ninth Circuit in the outstanding Ninth Circuit challenges. On May 24, 2007, PSE filed a petition seeking an Accounting Order requesting deferred accounting treatment for residential and farm energy exchange

benefit amounts credited to customers under Schedule 194 – Residential and Farm Energy Exchange Benefit, that have not been reimbursed by BPA. Due to timing differences between pass-through of Schedule 194 credits and receipt of payments from BPA and because of suspension of such payments from BPA, PSE credited to customers approximately $32 million more as of May 31, 2007, than the benefits received from BPA. In Order No 01 in Docket No. UE-071024, PSE was authorized to

a. commence deferred accounting treatment for the amounts credited to customers under Schedule 194 that have not been reimbursed by BPA commencing as of the date the Schedule 194 tariff changes to zero;

b. book monthly carrying charges on that deferral at PSE's approved net of tax rate of return until the deferral is recovered; and

c. amortize the total deferred balance including carrying charges over a time period to be determined in PSE's next general rate case ("GRC"). The total deferred balance to be amortized may be reduced by Residential Exchange Benefits PSE may receive in the future, but any such reduction would be dependent on future events.

This proforma adjustment, which increases expense by $4,440,313, represents the amortization over two years of the carrying costs only. For purposes of this adjustment, it is assumed that the deferral of amounts credited to customers will be received from BPA, and therefore is not included in determination of the revenue requirement in this case. However, during the course of these proceedings, PSE will true up this adjustment to include amortization of the deferral of amounts credited to customers if necessary as events warrant.

3. Adjustment to Move Legal Costs Associated with the Sales of Power from 557 to 923 – In the test period, there were $382,511 of legal costs associated with the sale of power. This restating adjustment increases 923 for that amount. The removal from 557 is included in the PCA page 4.03 and is supported by the prefiled direct testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT), and corresponding exhibits and workpapers thereto.

4. Cost of Wire Zone Vegetation Management Program – As discussed in the prefiled direct testimony of Ms. Sue McLain, Exhibit No. ___(SML-1CT), the Company will experience incremental costs associated with new NERC standards for creating a predictable and low-growing environment of vegetation under and adjacent to rights-of-way under transmission lines rated 200kV and above. These incremental costs are expected to be $4,000,000 in the rate year.

5. Increase in Service Contract Baseline Charges – As discussed in the prefiled direct testimony of Ms. Sue McLain, Exhibit No. ___(SML-1CT), baseline charges on service contracts are expected to increase. This proforma adjustment, which increases transmission expense by $16,577 and distribution expense by $1,032,693, represents the expected percentage increase over test year costs. These amounts may be trued-up

for changes to contract price increases during the course of these proceedings as warranted.

6. Adjustment of One-Time FAS 106 Curtailment Gain – During the test period, a settlement was reached in which IBEW participants elected to receive a lump sum payment in lieu of future post-retirement medical benefits. A one-time curtailment gain of $455,000 was recognized in relation to this settlement as a reduction to O&M expense. The $286,923 being removed from O&M in this restating adjustment represents the amount of the total curtailment gain that was booked to electric in the test period.

7. Summit Building Contractual Rent Increases and Amortization of Summit Buyout Purchase Option – This pro forma adjustment is made to reflect the deferred accounting treatment currently being requested under Docket No. UE-071876 ("the accounting petition") for the proceeds, net of incremental transaction costs, resulting from a Settlement Agreement to amend the PSE lease for its corporate headquarters buildings. The lease was modified by terminating and removing a purchase option and by extending the existing lease terms in consideration of a $20 million payment to the Company by Summit REIT, Inc. The Company is requesting that the total deferred balance be amortized over seven years commencing January 1, 2008 and shaped in accordance with scheduled

near-term contractual lease increases. The proceeds net of transaction costs are approximately $18.9 million. The adjustment shown on line 14 adjusts the test year rent expense for the Company's headquarters by the contractual annual rent increases between September 2007 and October 2009. This increase to lease expense is offset by the adjustment shown on line 15 which is made to represent the rate year amortization of the deferred payment which is shaped to the scheduled rent increases and which is being requested in the accounting petition. These two adjustments together decrease operating expenses by $486,094.

The total impact of all of the above adjustments is to decrease net operating income by $5,331,649.

(b) <u>Adjustments to Ratebase</u>

Restating and pro forma adjustment 4.14 adjusts the test year for the following ratebase items.

1. The reduction of $122,341 on line 26 represents the removal of costs from test period ratebase associated with land that was transferred to non-utility during the test period.

2. The addition of $3,245,319 on line 27 is to add to ratebase CWIP that is closed and in-service but not yet classified to plant. This restating adjustment is consistent with prior cases and is necessary to properly

reflect the ratebase that was in service during the test year.

4.15 Property Taxes

This pro forma adjustment reflects the estimated property tax levy rates to be paid in 2008 based upon 2007 value. This adjustment is done in the same manner as in prior general rate cases. The levy rates are the estimated values for 2008 and will be adjusted to actual during the course of this proceeding.

The effect of this adjustment is to decrease net operating income by $2,153,170.

4.16 Excise Tax and Filing Fee

This restating adjustment adjusts the test year to the actual expense for excise tax and the new Washington filing fee that should be recorded for these costs.

The effect of this adjustment is to increase net operating income by $454,544.

4.17 Director and Officer Insurance

This restating adjustment 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 total PSE assets and applying that percentage to the insurance cost. This result is then compared to what was actually booked during the test year.

The effect of this adjustment is to decrease net operating income by $23,276.

4.18 Montana Electric Energy Tax

This restating adjustment 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 at Colstrip as reflected in the power cost adjustment.

The effect of this adjustment is to decrease net operating income by $31,476.

4.19 Interest on Customer Deposits

This pro forma adjustment to operating income is the expense impact associated with using customer deposits as a reduction to ratebase. This pro forma adjustment adds the cost of interest for this item to operating expense. This presentation is consistent with decisions in prior general rate cases, and reduces net operating income by $599,090.

4.20 SFAS 133

This restating adjustment 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 $576,937.

4.21 Rate Case Expenses

In the Company's 2004 general rate case the Commission changed the method for future recovery of rate case expenses to a "normalized" methodology. Based on prior general rate cases, a "normal" level of expense was 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). A similar methodology was applied to determine a normalized amount of PCORC expense.

The Company has followed this methodology 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 to determine a normalized level of expenditures by averaging the costs associated with the last two general rate cases as one calculation and the last two PCORC cases as another calculation. This average level of costs was then spread over two years for each type of case, which reflects the actual time frame that has been experienced between general rate case filings and PCORC filings. This same two-year time frame was approved in the Company's 2006 general rate case and is the time frame that is consistent with the Company's anticipated timing of future rate case filings.

The average cost for a general rate case using this methodology is $2.948 million. This cost is allocated 50% to electric and 50% to natural gas, which results in a $1.474 million dollar average cost for each energy group. The average cost for a

PCORC case is $.325 million. This cost is allocated only to electric service for a total $1.799 million dollar average cost.

These average costs are then normalized for recovery over two years and are then compared to the amount the Company had actually recorded in the test year for rate case expense and the result increases net operating income by $131,455.

4.22 Deferred Gain/Loss on Property Sales

The purpose of this restating and pro forma 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 increases net operating income by $629,634.

4.23 Property and Liability Insurance

This pro forma adjustment reflects actual and 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 decrease net operating income by $405,390.

4.24 Pension Plan

This restating adjustment adjusts the test year to reflect cash contributions to the Company's qualified retirement fund. As the Company has not needed to make any tax deductible cash contribution, as determined by its plan actuary, since 2003 the cost of the pension plan is determined to be zero for the test period.

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 increase net operating income by $453,665.

4.25 Wage Increase

This pro forma adjustment reflects the impact of wage increases and associated payroll tax changes, as described in the prefiled direct testimony of Mr. Tom Hunt, Exhibit No. ___(TMH-1T). For represented (union) employees, the adjustment annualizes the wage increases granted in 2006, 2007, and estimated for 2008 and 2009. The percentage of wage increase for IBEW union employees from the test period through the rate year are 3.5% effective June 20, 2007, 3.25% effective April 1, 2008, and 3.25% effective April 1, 2009. The percentage of wage increase for UA union employees from the test period through the rate year are 3.5% effective October 1, 2006, 3.11% effective October 1, 2007, 2.85% effective October 1, 2008 and 2.84% effective October 1, 2009. Please note that corrected UA wage increases are shown in the prefiled direct testimony of Mr. Tom Hunt, Exhibit No. __ (TMH-1T). As these updated percentage increases were received too late to update this adjustment prior to filing, the Company will provide a corrected wage increase adjustment, plus related adjustments, during this proceeding. The percentage of wage increase for management employees from the test period through the rate year are 1.10% effective January 1, 2007, 3.02% effective March 1, 2007, .24% increase effective July 2, 2007, 3.5% effective March 1, 2008, and 3.5% effective March 1, 2009. These management increases have been weighted by prior year actual salary increases, as discussed by Mr. Karzmar.

This adjustment decreases net operating income by $2,855,717.

4.26 <u>Investment Plan</u>

This pro forma adjustment 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 decreases by $114,238 as the result of this adjustment.

4.27 <u>Employee Insurance</u>

This pro forma adjustment updates the test year insurance payments to the amount for the rate year. For IBEW employees, the estimated cost is based on the average Company contribution amount of $843 per eligible employee per month for the months of November and December 2008 and $910 per eligible employee per month for the months of January through October 2009. For UA employees, the estimated cost is based on the average Company contribution amount of $842 per eligible employee per month for the months of November and December 2008 and $910 per eligible employee per month for the months of January through October 2009. The amounts are the result of negotiations between PSE and the IBEW union and PSE and the UA union. The same average rate as the UA employees 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 55.72%.

The effect of this adjustment is to decrease net operating income by $985,713.

4.28 Incentive Pay

This restating adjustment uses a four-year average 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, the Company has used the years 2004 through 2007 and allocated the four-year average to electric and natural gas based on payroll distribution. The year 2007 is the current incentive amount estimated to be paid and will be trued up to actual during the course of this proceeding.

The incentive is then allocated to O&M expense and other accounts based on where payroll was charged during the test year. This amount is then compared to actual incentive pay expenses during the test year and results in a decrease in net operating income of $491,990.

4.29 Montana Corporate License Tax

This restating adjustment adjusts this tax for the current taxable income computed in the restating 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 $138,690.

4.30 <u>Amortization of Goldendale Generating Station Fixed Cost Recovery</u>

In Docket UE-070533 the Commission approved the following accounting treatment associated with the acquisition of Goldendale Generating Station: (1) defer the fixed cost component of operation and maintenance expense, depreciation, taxes, and cost of capital invested in ratebase, beginning with the filing date of the petition and ending with the effective date of new rates from the Company's 2007 PCORC; (2) book monthly carrying charges on the deferred costs at PSE's approved net of tax rate of return until amortization begins; and (3) amortize the total deferred balance including carrying charges over three years commencing with the earlier of January 1, 2009, or the effective date of new rates as a result of the Company's next general rate case, which is required to be filed within three months after the conclusion of a PCORC, unless the Commission approves a requested waiver.

This adjustment presents the costs discussed above and amortizes the costs over the requested three-year amortization period. These costs include normal operation and maintenance expense, the return on and of the investment during the period stated above and the interest cost booked on the deferral. Costs associated with the Goldendale Generating Station turbine outage and major maintenance expenses are not included in this adjustment. This adjustment also removes $10,843,497 of credits made to other operating expense at the time the monthly deferrals were recorded during the test period.

The impact of this proforma and restating adjustment is to decrease net operating income by $9,753,673.

Finally, this adjustment includes in ratebase the unamortized AMA balance of the deferral and the associated deferred federal income taxes at the end of the rate year. This restating adjustment, which adds $6,763,253 to ratebase, is necessary in order to recover the proper amount to cover the capital costs associated with this deferral. The accrual of interest will cease at the time the rates in this proceeding become effective and the unamortized balance is included in ratebase.

4.31 Storm Damage

This pro forma adjustment reflects adjustment of the test year expense level of storm damage expense, $10,996,358, 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, $7,987,354, is used to determine the annual normalized expense allowed for ratemaking purposes and is consistent with prior general rate case filings.

The Company is also requesting that the Commission set the level of IEEE defined storms to be $8 million for deferral purposes instead of the previous $7 million. This is the level of IEEE storm expense that would have to be incurred prior to the Company requesting deferral of IEEE related storm costs.

In the 2004 general rate case the Commission Staff had argued that the Company should be at risk for some storm damage expense in excess of what had been approved as normalized storm expense, which in that Docket was determined to be $4.6 million. In this argument, referenced by the Commission in Docket No. UG-040640, et al, paragraph 238, the Commission Staff used the proposed $7 million dollar IEEE cap as a cap to show that the Company would be able to defer any costs in excess of this limit. However, as shown on the current Storm Damage adjustment, actual storm expense has exceeded this $7 million dollar cap in two of the last three years. In 2005, the cap was actually $5 million instead of $7 million and the actual storm damage expense for September 30, 2005 was $2 million. Please see the prefiled direct testimony of Mr. Greg Zeller, Exhibit No. ___(GJZ-1T), for an explanation of why the storm damage expense recorded in a given year can exceed the threshold for catastrophic storm loss deferral. Based on historical storm damage experience, the Company is proposing that the appropriate level to set for the IEEE related deferral amount is the same level as the normalized storm damage expense determined in a general rate case filing. This level, $7,987,354 or $8 million, in this proceeding would still have the Company exposed to substantial storm damage risk.

PSE's ability to defer catastrophic storm costs also benefits customers. PSE customers have experienced lower storm-related normalized O&M expenses than they would have experienced if the storm event cost deferral mechanism were not in place. For example, during the test year, storm O&M before deferral totaled $112 million which is $104 million greater than the rate year normalized O&M

expenses of $8.0 million. PSE's authority to defer catastrophic storm losses that meet the IEEE catastrophic storm event definition allows PSE to spread out the cost impacts of storm events over a multi-year period and, as a result, lessen the volatility of required rate adjustments. The current catastrophic loss deferral process also provides for timely third party review of storm-related expenses.

As in prior general rate cases, the second part of the Storm Damage adjustment amortizes the costs related to catastrophic storms that have been deferred. Due to the large deferred balance associated with the December 2006 catastrophic storm, $83.6 million, which is discussed in the prefiled direct testimony of Mr. Greg Zeller, Exhibit No. ___(GJZ-1T), the Company proposes that this specific storm be amortized over six years instead of three years. The Company is proposing this change in amortization period for the December storm to mitigate rate impact on customers. The deferred costs associated with other catastrophic storms, which total $28.5 million are amortized over three years, which is the same deferral period authorized by the Commission in previous dockets. The total amortization for this part of the storm damage adjustment will be amortized each year until the account balance is zeroed out or until it is changed in a subsequent general rate case filing.

The effect of this adjustment is to decrease net operating income by $10,781,738.

4.32 **Regulatory Assets**

This pro forma adjustment adjusts the production related regulatory assets, net of deferred federal income taxes, to their projected rate year average of the monthly averages balances. This adjustment calculates the regulatory assets and liabilities associated with production plant based on their projected rate year balances as agreed to in the PCA Settlement from the 2001 general rate case. On line 15 of this adjustment the Tenaska regulatory asset amortization is shown separately as this part of the amortization is considered flow through for tax purposes.

In the original proceeding associated with the buy down of the Tenaska fuel prices, Docket UE-971619, the principal buy down amount of $215 million was treated as a flow through item for rate recovery. Because the IRS would only allow a straight-line amortization of the $215 million over 15 years, the customer receives the tax benefit associated with this tax amortization and not the book amortization actually recorded for the $215 million. In the Federal Income Tax Adjustment the test year amortization, $19.4 million, is removed and the tax amortization, $14.3 million, is treated as a tax deduction. In this adjustment the increase in amortization between the rate year amortization, $26.5 million, and the test year amortization, $19.4 million, is treated as non-tax deductible.

The effect of all of these adjustments is to decrease net operating income by $8,718,601 and decrease ratebase by $63,830,658.

4.33 **Depreciation Study**

This restating adjustment calculates the impact of implementing the depreciation study discussed in the prefiled direct testimony of Mr. Richard Clarke, Exhibit No. ___(CRC-1T). PSE hired Mr. Clarke and his firm, Gannett Fleming, Inc., to evaluate the Company's depreciation rates and provide an update to the current depreciation rates which are based on a depreciation study as of December 31, 2000. Mr. Clarke also provides an explanation in his testimony of some of the major changes between the new depreciation rates and the current depreciation rates. One of the larger changes in electric depreciation rates is attributable to the rate change on computer equipment. This equipment has been depreciated at rates varying up to 28 years. The new study has this equipment being depreciated over five years. This change alone increases electric depreciation expense by $4,867,180.

To adjust the test year depreciation expense to the new depreciation rates the Company used the relationship of the new depreciation rate for a specific asset account to the old depreciation rate for that account times the test year depreciation expense for that particular account. For example, account 362 – Non-project Distribution Station Equipment has a depreciation rate of 2.19% and the new rate is 2.23%. The relationship of the new rate to the old rate is 2.23/2.19 or 101.83%. The test year depreciation expense is $8.5 million and when multiplied by 101.83% the new depreciation expense is $8.6 million. The result of this calculation for all asset accounts were then totaled and compared to the total depreciation expense for the test period for electric, gas and common plant.

For electric plant and common plant allocated to electric the results of this calculation are shown on lines 1-4 of this adjustment. Lines 6 through 15 of this adjustment remove the impacts of Statement of Financial Accounting Standard 143, Accounting for Asset Retirement Obligations which is not includable in rates. On lines 22 and 23 the impact on current Federal income tax and deferred taxes are presented. There is a shift between these two tax types because the higher book depreciation rates reduce the currently payable taxes. Because the tax depreciation does not change, the offsetting impact is to lower deferred taxes.

Q. Mr. Clarke's Depreciation Study, Exhibit No. ___(CRC-3T), page 67, shows that for Common Plant, account 391.2, Computer equipment < $20k that the acquisition value is $28,637,164 and the proposed depreciation rate is 20% yet expense is $10,442,663. Would you please explain why the depreciation expense is so high?

A. Yes. For purposes of the depreciation study Mr. Clarke reflects the calculation of depreciation expense on each of the last five year balances as having to be recovered within five years of when the assets were put into service. For example, any remaining balance in this account for 2002 has to be recovered in one year; the balance in the account for year 2003 has to be recovered in two years, and so on, until the account balance in 2006 is recovered in five years.

The Company is proposing to implement the change in a different manner. The Company calculated the depreciation expense in the same manner as the other accounts, which was described earlier. This in effect treats the current balance in this account as if it were closed to in-service in the test year. The expense that we calculate for this account is $6,066,423, which is slightly greater than 20% of the $28,637,164. The reason for this higher amount is that the calculation described above takes into consideration retirements and additions that happened during the test year, which would impact the test year depreciation expense. The Company proposes that for all accounts being switched to a shorter amortization life, the balance in the account at the time of implementation of the new amortization rate be treated as year one, which will be amortized over the new amortization period.

Q. Please continue with your explanation of the adjustments.

A. On lines 28 and 29 of this adjustment, ratebase is adjusted for the impact of the change in depreciation expense, because this change in expense would impact both accumulated depreciation and deferred taxes on the balance sheet. The effect of all these adjustments is to decrease net operating income by $8,083,203 and decrease ratebase by $2,660,162.

4.34 <u>Skagit Facility</u>

In April 2007, the Company petitioned the Commission to authorize the sale of the Skagit Service Center as the property was needed by The State of Washington

Department of Transportation, Docket No. UE-070643. This restating adjustment removes the test year costs associated with the original Skagit Service Center and proforms in the cost of the replacement Service Center. The sale of the original Skagit Service Center was deferred and is being credited to customers in the Deferred Gains/Losses on Property Sales Adjustment.

The effect of this adjustment is to increase ratebase by $19,640,179 and to decrease net operating income by $809,652.

4.35 Production Adjustment

This pro forma adjustment decreases production related ratebase and certain production expenses by the production factor that was used for calculating power costs. The production factor is the ratio of the test period normalized delivered load to the rate year delivered load, which is 96.661%. This adjustment is applied to power cost related items so that the growth in load from the test year, the load rates are spread on, to the rate year will increase revenues to cover the projected rate year level of power costs. The ratio of test year delivered load to rate year delivered load is the reciprocal of the 3.339% 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 $3,234,351 and ratebase is decreased by $42,851,342 as the result of this adjustment.

This adjustment is the last Company adjustment for pro forma and restating adjustments to the electric service test year.

V CALCULATION OF THE ELECTRIC REVENUE DEFICIENCY

A Revenue Deficiency Based on the Pro Forma and Restated Test Period

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

A. Exhibit No. ___(JHS-5) presents the calculation of the revenue deficiency based on the pro forma and restated test period. The different pages in Exhibit No. ___(JHS-5) are:

5.01 General Rate Increase

This schedule, shown on Exhibit No. ___(JHS-5), page 5.01, shows the test period pro forma and restated ratebase, line 1, and net operating income, line 6. Based on $3,305,098,647 invested in ratebase, an 8.60% rate of return and $175,600,500 of net operating income, the Company would have a retail revenue deficiency of $174,482,512.

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 prefiled direct testimony of Mr. Donald E. Gaines, Exhibit No. ___(DEG-1T). The rate of return is 8.60% and 7.29% 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 Utilities and Transportation Commission filing fee, and bad debts. The conversion factor used in the revenue requirement calculation, taking into consideration the adjustments discussed earlier, is .6214308.

Q. Is the Company requesting in this filing that any deferred Power Cost Adjustment expenses 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.

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B **<u>Calculation of the Power Cost Baseline Rate for this Proceeding</u>**

Q. Is the Company proposing a Power Cost Baseline Rate in this case consistent with the 2006 general rate case and 2007 PCORC?

A. Yes, the Company's proposed new Power Cost Baseline Rate has been calculated in the same manner as in the 2006 general rate case and 2007 PCORC. This is shown on Exhibit No. ___(JHS-7C). The proposed new Power Cost Baseline Rate is $63.012 per MWh before revenue sensitive items, compared to the current Power Cost Baseline Rate of $59.813 per MWh that was approved in the 2007 PCORC.

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 November 2008 through October 2009. For this proceeding, PSE has used the test year ending September 2007.

In addition to providing the normal power cost restating and pro forma adjustments, PSE has provided pro forma adjustments to account for changes to its ratebase and operating expenses associated with the purchase of the of new resources and purchase power agreements discussed earlier. These costs are included in the appropriate line items on Exhibit A-1.

Q. Please explain what Exhibit No. ___(JHS-7C) presents.

A. Exhibit No. ___(JHS-7C), 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, 7.29%, 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 the PCA defined 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, the Company has divided this result by the test year delivered load to calculate the new Power Cost Baseline Rate of $63.012 per MWH before revenue sensitive items.

Q. Please explain the remaining pages included in Exhibit No. ___(JHS-7C).

A. The remaining pages of Exhibit No. ___(JHS-7C) are equivalent to 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.

C. <u>Proposed Changes to the Power Cost Only Rate Case Mechanism</u>

Q. Has the Company met with other parties to discuss changes to the Power Cost Only Rate Case Mechanism ("PCORC") as directed by the Commission in Docket No. UE-070565?

A. Yes. The Company met several times with Commission Staff, Public Counsel and Industrial Customers of Northwest Utilities ("ICNU") as part of the PCORC Collaborative.

Q. Is the Company presenting any changes to PCORC mechanism in this filing?

A. No. The parties discussed several different methods of modifying the PCORC mechanism; however, agreement could not be reached as to what conditions would generate a PCORC filing or if the PCA and the PCORC should be considered separate from each other. The parties will be filing a report on these discussions sometime after the filing of the Company's general rate case.

Q. Were you part of the Company team that met with other parties in Docket No. UE-011570 to design the PCA mechanism?

A, Yes, along with Mr. Bill Gaines, who is no longer with the Company, Ms. Harris and Mr. Elsea.

Q. Do the Settlement Terms for the PCA Mechanism from Docket Nos. UE-011570 and UG-011571 have restrictions on when a PCORC can be filed?

A. No. The Settlement Stipulation does not restrict when a PCORC can be filed. It describes the PCORC as a *periodic* proceeding specific to power costs to true up the Power Cost Rate to all power costs identified in the Power Cost Rate, and to add new resources to the Power Cost Rate. The relevant paragraph in the Settlement Stipulation is paragraph 8. It states as follows:

> 8. **Power Cost Only Rate Review:** In addition to the yearly adjustment for power cost variances, there would be a periodic proceeding specific to power costs that would true up the Power Cost Rate to *all power costs* identified in the Power Cost Rate. The Company can also initiate a power cost only proceeding to add new resources to the Power Cost Rate. In either case, the Company would submit a Power Cost Only Rate filing proposing such change. This filing shall include testimony and exhibits that include the following:
> • Current or updated least cost plan
> • Description of the need for additional resources (as applicable)
> • Evaluation of alternatives under various scenarios
> • Adjustments to the Fixed Rate Component
> • Adjustments to the Variable Rate Component
> • A calculation of pro forma production cost schedules that are consistent with this docket, including power supply and other adjustments impacting then current production costs.
>
> (Emphasis in original)

A copy of the Settlement Agreement is provided in Exhibit No. ___(JHS-8) for reference.

Q. Should the PCORC be limited to the sole purpose of adding new resources to the Power Cost Rate?

A. No. As explained by Mr. Markell, in Exhibit No. ___(EMM-1CT), and Ms. Harris, in Exhibit No. ___(KJH-1HCT), and as discussed in more detail below, the PCORC is needed now more than ever by the Company both to update its power costs and to bring new resources before the Commission for approval in a timely fashion.

The PCA Settlement actually encourages this resource review by limiting the type of costs that the Company can include in the PCA calculation for new resources. Paragraph 7 says in part that new resources with a term greater than two years may be included in the PCA allowable cost at the lesser of the actual cost or the average embedded cost in the PCA including transmission. Exhibit G then provides an example of a new resource being added to the Company's portfolio. As can be seen on Exhibit G, page 30 of 30, Exhibit No. ___(JHS-8), only variable costs and transmission are included in the calculation. No fixed cost recovery, such as return on and of the resource, is allowed. For the Company to be able to include fixed costs in the PCA mechanism, the Company must either get them approved by the Commission, which would then allow the fixed costs to be included on Exhibit A-1 of the PCA mechanism, or file an Accounting Petition for deferral and consideration in a later proceeding. This feature of the PCA ensures that the Company would have approval of a new resource before costs above the average embedded rate are allowed to be considered for recovery from customers.

Q. How does Exhibit A-1 impact the PCA Mechanism?

A. Exhibit A-1 is important for two reasons. First, it is the exhibit that calculates the Power Cost Rate used to calculate changes in revenue requirement in a PCORC. Second, it is the source of information used in calculating the over or under collection of power costs during a PCA period. Exhibit B, page 21 of 30, in Exhibit No. ___(JHS-8) uses the total of fixed costs allowed in a general rate case or PCORC filing to determine the amount of fixed costs allowed in a PCA period as shown on lines 4 and 6. These costs, as presented on Exhibit A-1, do not vary without a general rate case filing or a PCORC filing. If the Company does not request that Exhibit A-1 be updated for the addition of a new resource then the new resource's fixed costs cannot even be considered as part of the true up for power costs. This is the reason that the Company had to request the Commission approve the deferral of fixed costs associated with the Goldendale purchase discussed earlier in my testimony.

Exhibit A-1 is also used on Exhibit B line 31 to provide the baseline power cost rate. This rate times the actual delivered load for a period is the amount of power costs that are included in customers' rates. The product of this calculation is compared against the sum of the fixed costs from Exhibit A-1 plus the actual allowable variable power costs during the period plus any adjustments as illustrated on lines 21 through 24 of Exhibit B to determine the over or under recovery of allowed power costs. The over or under recovery of costs are then compared to the sharing bands to determine if any deferral of power costs is needed.

Q. If the Company can file a PCORC any time after a general rate case as power costs change, how does this impact the risk that the Company presently bears for changes in power costs?

A. The Company remains at risk for changes in power costs that vary from normalized conditions such as weather and water, forecast error and for changes in market prices until the PCA Baseline Rate changes. As stated in the last bullet of paragraph 8 of the Settlement Stipulation, the Company must file its power costs in accordance with the methodologies used in "this Docket" meaning the 2001 general rate case.[1] These methodologies include normalized weather, normalized water, current contract prices, forecast rate year, approved models, etc. It does not mean that the Company has to absorb cost changes to its portfolio when the composition of the Company's portfolio changes. When such portfolio composition changes, the current Baseline Rate is no longer valid as the Company's future power costs can change dramatically. As explained above, the PCA was designed to compel the Company to come in to change its power costs when its portfolio changes. Without an update to Exhibit A-1 the Company can not even measure all of its actual power costs that should be allowed for recovery under the PCA mechanism. Thus, the PCA mechanism and its component, the PCORC, are not meant to be separate but instead work hand in hand.

Q. Is the PCORC mechanism too complex?

A. The PCORC deals with a complex subject--the forecast of future power costs for a significant load. The PCORC was meant to be simplified in that it is based on approved power cost methodologies from the most recent general rate case plus the prudence of new resources. It does not deal with cost of money or changes in non production related expenses or ratebase. These topics are reserved for general rate cases. Also, new methodologies for determining power costs were intended to be limited to the general rate filings.

The Company has completed three PCORC proceedings since the Commission approved the PCA mechanism in 2002. The parties have been able to work together on these cases to complete the expedited review in the timely manner anticipated by the parties to the Settlement Stipulation.

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[1] This should have been stated as "the most recent general rate case filing" rather than "in this

Q. Please explain the benefits that the PCORC provides.

A. Customers benefit because the PCORC uses what would have been growth in revenues associated with production assets to offset power cost increases. Also, customers benefit because the PCORC allows resource planning flexibility so that the Company can make the most cost effective power decisions and bring much needed generation resources into service in a timely manner. The PCORC benefits the Company by allowing for timely recovery of the Company's power cost investments. The PCORC mechanism also allows the Commission to consider the prudence of new resources or changes in power costs in a timely fashion.

Additionally, as discussed above, the PCORC is a part of the PCA mechanism which provided a negotiated balance of risks and benefits to customers and the Company. In the Company's 2006 general rate case other parties argued, and the Commission agreed, that the negotiated balance of risks and benefits associated with the PCA should continue. The factors that led to the creation of the PCA and the PCORC component of the PCA remain more important today than ever. Accordingly, I see no reason for revising the PCORC at this time.

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Docket."

D. <u>Proposed Changes due to the Pending Merger</u>

Q. Have you or Mr. Karzmar included any savings due to the pending merger that was announced between PSE and the consortium of infrastructure investors?

A. No. Both electric and natural gas revenue requirements are calculated based on PSE continuing operations as before. As this merger is not between two utilities that could have synergies by combining operations it is not expected that there will be significant changes in PSE operating costs. If the merger is approved there may be some cost savings associated with items such as New York Stock Exchange fees. We expect that merger savings, if any, will be addressed in a future historic year and the merger application proceeding.

VI. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.