EXHIBIT NO. ___(KJB-1~~C~~T)
DOCKET NO. UE-13____
2013 PSE PCORC
WITNESS: KATHERINE J. BARNARD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-13____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
KATHERINE J. BARNARD
ON BEHALF OF PUGET SOUND ENERGY, INC.

REVISED
JUNE 7, 2013

APRIL 25, 2013

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF KATHERINE BARNARD

PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

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

A. My name is Katherine J. Barnard and I am Director, Revenue Requirements and Regulatory Compliance with Puget Sound Energy, Inc. ("PSE"). My business address is 10885 NE 4th Street, Bellevue, Washington, 98009-5591.

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

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

Q. What is the nature of your testimony in this proceeding?

A. My testimony describes adjustments for changes in PSE's power supply costs that are included in the proposed Power Cost Rate, including the rate impact of: (1) adding new resources, the Ferndale Generating Station and the Electron purchased power agreement, to PSE's power supply portfolio; (2) capital upgrades at the Snoqualmie and Baker Hydro Plants to meet Federal Energy Regulatory Commission ("FERC") licensing requirements; (3) the sale of the Electron Hydroelectric Project ("Electron") and (4) updating resource expenses to account for current costs and expected power costs.

The total rate decrease resulting from these adjustments is $618,683, an average

0.03 percent decrease over the rates set in PSE's 2011 general rate case, Docket Nos. UE-111048 and UG-111049 ("2011 GRC"), which became effective on May 14, 2012.

II. ADJUSTMENTS TO THE POWER COST RATE

Q. Please explain what is meant by the Power Cost Rate.

A. The Power Cost Rate is the product of the parties' settlement of PSE's 2001 general rate case, Docket Nos. UE-011570 and UG-011571. In June 2002, the Commission approved the parties' Settlement Stipulation for Electric and Common Issues in that docket ("Settlement Stipulation"). *See* Commission's Twelfth Supplemental Order (dated June 20, 2002) ("Twelfth Supplemental Order"). Among other things, the Twelfth Supplemental Order authorized the use of a Power Cost Adjustment Mechanism ("PCA") as a method for adjusting PSE's power costs. *See Settlement Terms for the Power Cost Adjustment Mechanism*, Exhibit A to the Settlement Stipulation, attached as the second exhibit to my prefiled direct testimony, Exhibit No. ___(KJB-3).

As described in the Settlement Stipulation, the PCA sets forth an annual accounting process for a sharing of costs and benefits between PSE and its customers over four graduated levels, or "bands," of power cost variances.[1] *See* Exhibit No. ___(KJB-3) at page one. The PCA distinguishes between power costs and all other costs included in general rates and allows PSE to file an application seeking adjustment

[1] The PCA had an overall cap on PSE's share of power cost variances of $40 million (+/-) over the four year period July 1, 2002 through June 30, 2006, which is now expired.

to all of PSE's power costs identified in the Power Cost Rate. *See* Exhibit No. ___(KJB-3) at page two. The Settlement Stipulation includes a table that shows the allocation of costs between costs that can be adjusted through the PCA, and other, non-power costs, which are not adjusted through the PCA. Two categories of costs comprise the Power Cost Rate: variable rate components and fixed rate components. *See* Exhibit No. ___(KJB-3) at page four.

Q. Have there been changes to the PCA and the method of determining the Power Cost Rate since the Settlement Stipulation was approved by the Commission?

A. Yes. Several changes have been made to the PCA since the Settlement Stipulation was approved by the Commission. These include:

(i) revising the accounting period for the PCA accounting process to a calendar year;[2]

(ii) eliminating Schedule E;[3]

(iii) including interest costs and commitment fees associated with electric hedging activities in the Power Cost Rate;[4]

(iv) computing rate spread based on the peak credit methodology utilized in computing the rate spread in the Company's most recent general rate case proceeding rather than referencing the peak credit methodology used in the 2001 general rate case;[5]

(v) extending the expected procedural schedule from five to six months;[6]

(vi) limiting filing power cost updates to one per power cost only rate case ("PCORC"), with an additional update allowed as part of the compliance filing if the Commission determines the update is necessary due to increased

[2] Docket UE-050870
[3] Docket UE-060266
[4] Docket UE-060266
[5] Docket UE-070565
[6] Docket UE-072300

gas costs and orders that such update be made as part of the compliance filing;[7]

(vii) prohibiting the overlap of PCORC and general rate cases, except for requests for interim rate relief;[8] and

(viii) shortening data request response time from ten to five business days at the outset.[9]

Q. When are the accumulated PCA costs and benefits allocations reviewed?

A. PSE files an annual PCA compliance report in March of each year, which details the power costs included in the deferral calculation for the annual period ending December 31 of the prior year.

Q. How is the Power Cost Rate adjusted?

A. Independent of the yearly accounting and adjustment for power cost variances, PSE may also apply to the Commission to true up the Power Cost Rate to all power costs identified in a PCORC. In order to true up the Power Cost Rate, the Settlement Stipulation requires, among other things, testimony and exhibits that include

- Adjustments to the fixed rate components of the Power Cost Rate;
- Adjustments to the variable rate components of the Power Cost Rate; and
- A calculation of pro forma production cost schedules that are consistent with the costs presented with the Company's most recent general rate case, including power supply and other adjustments impacting production costs.

My testimony provides this required information in support of PSE's present application to true up its Power Cost Rate through this PCORC.

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[7] *Id.*
[8] *Id.*
[9] *Id.*

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

A. The third exhibit to my prefiled direct testimony, Exhibit No. ___(KJB-4~~C~~), summarizes the adjustments used to determine the new Power Cost Baseline Rate. As stated earlier, the PCA makes a distinction between: (i) power costs, as determined in a PCORC; and (ii) all the other costs, which are determined in a general rate case. In both a general rate case and a PCORC, the Company uses a future rate year to determine certain power costs and then pro forms those costs back to the test year. Using such methodology for this proceeding, PSE summarized the power cost adjustments, plus restating adjustments, associated with production costs in Exhibit No. ___(KJB-4~~C~~). The proposed rate year used for these adjustments is November 2013 through October 2014. For this proceeding, the test year is the period October 1, 2011 through September 30, 2012 (the "test year").

Section 8 of the Settlement Stipulation authorizes the Company to initiate a power cost only proceeding to add costs of new resources to the Power Cost Rate. In addition to the above power cost adjustments, pro forma adjustments have been made to account for changes to PSE's rate base and expenses associated with: (i) the purchase of the Ferndale Generating Station, which is discussed in more detail in the prefiled direct testimonies of Roger Garratt, Exhibit No. ___(RG-1~~C~~T) and Michael Mullally, Exhibit No. ___(MM-1HCT); (ii) the Snoqualmie Falls Hydro Generating Electric Project; and (iii) the Baker River Electric Project for additions of the Lower Baker Floating Surface Collector and the Lower Baker Powerhouse. Both hydro facilities are discussed further in the prefiled direct testimonies of Paul Wetherbee, Exhibit No. ___(PKW-1CT), and Douglas S. Loreen, Exhibit No. ___(DSL-1T). Each of these plants will go into service prior to the start of the rate year and generate low cost, economical energy for customers. Finally, developments with the sale of the Electron project and its impact to the Baseline Rate are discussed further later in my testimony and in Mr. Mullally's prefiled direct testimony, Exhibit No. ___(MM-1HCT).

Q. Please explain what Exhibit No. ___(KJB-4~~C~~) represents.

A. The first column of Exhibit No. ___(KJB-4~~C~~) shows the rate base and production costs from the test year that will be considered in setting the Power Cost Baseline Rate. The first column, titled "Test Year Actual 12 months ended September 30, 2012", sets forth the rate base and actual production costs for the test year. The columns to the right of this first column show the impact of the pro forma and restating power cost adjustments PSE is proposing for the pro forma rate year. These adjustments are presented in more detail on the succeeding pages referenced in the title of a particular column. The work papers supporting these adjustments have been provided to WUTC Staff and intervenors. The total of the test year amounts plus the pro forma and restating adjustments is shown in the column titled "Adjusted 12 months ended September 30, 2012" on page four of Exhibit No. ___(KJB-4~~C~~). This column represents the costs to be used in determining the Power Cost Baseline Rate, which in turn is used to calculate the required rate increase. These are the same amounts shown in the first column of the fourth exhibit to my prefiled direct testimony, Exhibit No. ___(KJB-5~~C~~), "Exhibit A-1 Power Cost Rate."

III. ADJUSTMENTS TO TEST YEAR POWER COSTS

Q. Please describe each of the adjustments presented in Exhibit No. ___(KJB-4~~C~~).

A. The adjustments are:

1. **<u>Power Cost</u> – Page one of Adjustment-1** lines three through eight and lines 12 and 13 present the rate year pro forma power costs presented by David Mills in the second exhibit to his prefiled direct testimony, Exhibit No. ___(DEM-3). Line nine presents the production operations and maintenance costs ("production O&M") presented by L. Edward Odom in the second exhibit to his prefiled direct testimony, Exhibit No.___(LEO-3C). These costs are the projected rate year fixed and variable production related costs for PSE's rate year power supply portfolio that are adjusted to test year levels using the relationship of normalized test year delivered load to rate year delivered load ("production factor"). These projected costs are a pro forma adjustment to the test year costs shown on the first page of Exhibit No. ___(KJB-4~~C~~).

The variable transmission income adjustment on line 13 captures revenue earned under PSE's Open Access Transmission Tariff ("OATT"). Under the PCA Mechanism, these revenues are typically included in the power cost base line rate by adjusting revenues to equal the most recent three-year average after being adjusted for non-recurring items. FERC is currently in the final stages of reviewing

PSE's OATT tariff, which the Company filed in January of 2012. The new tariff is formula driven and would adjust annually. PSE and the lead OATT rate case intervenor, Bonneville Power Administration ("BPA"), have agreed upon an Offer of Settlement ("the Settlement") on the OATT formula rate case proceeding. The Settlement was filed with FERC on February 14, 2013, and is pending FERC approval. The OATT rate proposed in the Settlement is expected to be in effect on June 1, 2013, and PSE anticipates FERC approval of the Settlement by the time PSE files its supplemental testimony in this proceeding. These rates are not expected to change from those proposed in the most recent agreement drafts and included in the calculation of this baseline rate. The variable transmission revenues included for this PCORC are calculated by re-pricing the most recent three-year average of transmission volume across the respective lines at the OATT rate included in the Settlement. Using this calculation, the pro forma variable transmission income included in the Baseline Rate is $6,545,360.

Finally, line ten presents the transmission expenses that are recovered through the PCA Mechanism related to the Third AC, Northern Intertie and Colstrip transmission lines. This adjustment is the result of applying the production factor to these test year expenses.

The second page of **Adjustment-1** is shown on page five of Exhibit No. ___(KJB-4~~C~~). Page five presents an overview of the total of the power cost categories discussed above and demonstrates in which of my Adjustments they are included. The final column on page five represents the amount of the total costs shown in

Adjustment-1. As certain power costs and operation and maintenance ("O&M") costs are included in other adjustments, page five provides a reconciliation from Mr. Mills's and Mr. Odom's rate year projections to the final adjusted rate year power cost and O&M projections included in **Adjustment-1**. Amortization of regulatory assets are removed from amounts included in **Adjustment-1** since they are included in adjustments 15, 18, 19, 20 and 21, which are discussed further later in my testimony. Test year benefits and taxes are re-classified out of Mr. Mills's and Mr. Odom's power costs and production O&M totals and reflected separately on lines 15a and 15d on page one of Exhibit No. ___(KJB-4~~C~~). The remaining rate year power costs have been adjusted to test year power cost levels by the production factor discussed later in my testimony and are the amounts reflected in **Adjustment-1**.

The total power cost adjustment decreases costs by $136,838,477.

2. **Montana Energy Tax – Adjustment-2** pro forms the taxes due in the State of Montana that are assessed on Colstrip generation. This adjustment compares the forecast generation of the Colstrip plants at the current Montana tax rate to the actual tax expensed in the test year. The adjustment more than doubles the level of expense that was incurred in the test year because the generation in the test year was lower as Colstrip Units 1 and 2 were off-line for a total of 61 days during the second quarter of 2012. The units were off-line for planned maintenance outages, boiler and scrubber cleaning and were in reserve shutdown due to economic displacement caused by low market prices as a result of excess hydro and wind generation in the region. This adjustment increases expense by $918,003.

3. **<u>Lower Snake River Phase 1</u> – Adjustment-3** restates the Lower Snake River Phase 1 Project production plant that went into service February 29, 2012 and is reflected in the beginning production rate base at the average of the monthly averages ("AMA") for eight months. This restating adjustment is necessary so that a full year of plant costs and depreciation are properly recognized for this plant as allowed in the 2011 GRC. This adjustment increases rate base by $228,877,317 and expense by $11,895,245.

4. **<u>Snoqualmie Falls Hydroelectric Redevelopment Project ("Snoqualmie Falls Project")</u> – Adjustment-4** presents the rate base and expenses associated with the Snoqualmie Falls Project. On June 29, 2004, the FERC issued PSE its current license to operate the Snoqualmie Falls Hydroelectric Project, FERC Project No. 2493. The run of the river Project consists of a diversion dam and two powerhouses located on the Snoqualmie River in the city of Snoqualmie and King County, Washington. As licensed, PSE will increase the installed capacity from 44.4 MW to 54.4 MW. Existing recreation facilities consist of viewing decks, picnic areas, trails, restrooms, and an outdoor education center, which are provided as requirements of the License. The in-service date, plant costs and expenses used in calculating this adjustment are provided by Messrs. Loreen and Wetherbee, and are discussed in their prefiled direct testimony, exhibits and workpapers.

This pro forma adjustment presents the rate base and expenses associated with the Diversion Dam, Plant 2 and Plant 1 closing to plant in October 2012, April 2013 and July 2013 respectively. The in-service date for Plant 1 is an estimated date. To the extent the actual closing date differs from this estimate, the impact to this adjustment (and to the Snoqualmie Deferral **– Adjustment 5** discussed below), may be updated in the supplemental filing during the course of this proceeding. The expected output from the redeveloped project has been included in the AURORA power cost model run for the rate year. The entire facility was off line in the rate year of the 2011 GRC and accordingly, there was zero generation for the Snoqualmie Falls Project in the 2011 GRC. The plant balance of $301,060,534, shown on line two of this adjustment, is the adjusted rate year plant cost for the project.

Q. Please explain how the rate base was calculated for rate purposes.

A. The total estimated cost of capital investment of the Snoqualmie Falls Project for each month of the rate year was used to determine the AMA plant balance of the rate period. To calculate the depreciation expense, the 31 years remaining out of 40 years of the FERC License was used to determine the depreciation rate of 3.19 percent, which represents the average deprecation rate of the three projects based on their individual in-service dates and the remaining period left on the Snoqualmie Falls Project license. The depreciation rates were developed by determining the amount of annual depreciation expense necessary to recover the net book value over the average remaining service life. The accumulated depreciation AMA balance of $9,042,644 is shown on line three of this adjustment.

Deferred taxes associated with the tax depreciation of the plant were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(1)-1(h). For the Snoqualmie Falls Project, the deferred tax calculation is based on twenty-year tax depreciation with an additional half-year Bonus Depreciation included in tax depreciation for the first year it is in service. Additionally, as part of the American Recovery and Reinvestment Act of 2009, PSE is eligible to receive a U.S. Treasury Grant ("Treasury Grant"), which results in a reduction to the tax basis for the Snoqualmie Falls Project. The half year convention for tax depreciation, the bonus tax depreciation of 50 percent in the first year, and the reduction to tax basis resulting from the Treasury Grant were applied when determining the deferred tax liability for the rate year. The Deferred Income Tax Liability balance of $42,407,216 is shown on line 4 of this adjustment.

The total of all the adjustments described above increases rate base by $249,610,673.

Q. Please describe the expense adjustment.

A. The calculation of total book depreciation expense of $9,609,270 shown on lines 11 and 12 is explained above. The depreciation associated with the Treasury Grant tax basis reduction shown on line 12 is not tax deductible. The revenue adjustment for flow through taxes of $783,919 is shown on line 13 and represents the gross-up associated with the non-taxable depreciation on Line 12. The rate year power generation and production O&M costs associated with the Snoqualmie Falls Project are included in Power Costs **Adjustment-1** and are supported by the prefiled direct testimonies of David Mills, Exhibit No. ___(DEM-1CT) and L. Edward Odom,

Exhibit No. ___(LEO-1CT), respectively.

The property insurance for the Snoqualmie Falls Project is included in the Property Insurance **Adjustment-14**. As discussed in more detail in **Adjustment-13** below, in Docket Nos. UE-130137 and UG-130138, PSE has proposed a tracker, Schedule 140, for recovery of property taxes. Therefore, property taxes for Snoqualmie are not included in this adjustment as it is assumed they will be tracked in a separate tariff filing. This adjustment increases expense for electric operations by $10,393,189.

Q. Please explain the Treasury Grant.

A. The Treasury Grant is a subsidy provided by the U.S. government per Section 1603 of the American Recovery and Reinvestment Act of 2009 for certain renewable energy projects. For hydroelectric projects providing incremental generation due to improvements as defined by the Internal Revenue Service Code Section 45, the Treasury Grant is an alternative to Production Tax Credits, which some companies have not been able to use in a timely fashion. The Treasury Grant is equal to 30 percent of the qualifying investment, less an 8.7 percent sequestration reduction, as discussed further in Section VI of Mr. Loreen's prefiled direct testimony, Exhibit No. ___(DSL-1T). The Treasury Grant reduces the tax basis for accelerated tax depreciation by one half of the grant received.

For PSE, Treasury Grants are passed back to customers outside of general rates and the general rate case process, in Tariff Schedule 95A. Accordingly, the rate impact of the Treasury Grant itself is not included in this adjustment other than to include

5. **Snoqualmie Falls Project Deferral - Adjustment-5** includes the estimated rate year amortization expense and net rate base amount for deferred costs associated with the Snoqualmie Falls Project. Pursuant to RCW 80.80.060(6), electric companies may defer costs of base load electric generation facilities that comply with the greenhouse gas emission standards. In 2009, the Legislature amended RCW 80.80.060 to allow for deferral of costs associated with an electric company's ownership of an eligible renewable resource, as defined in RCW 19.285.030(11). Specifically, part b) of the definition provides that hydroelectric generation projects producing incremental electricity as a result of efficiency improvements completed after March 31, 1999 qualify as renewable resources. On February 9, 2011, as a result of PSE's filing to obtain qualification to receive treasury grants, FERC granted PSE certification under the Energy Policy Act of 2005 section 1301(c) that these improvements have resulted in incremental generation. On April 18, 2013 PSE submitted to the Commission a Notice of Intent to Defer Costs, which was assigned Docket No. UE-130559. PSE began deferring the costs associated with the diversion dam and Plant 2 beginning on Plant 2's in-service date of April 17, 2013. PSE will begin to defer costs associated with Plant 1 on its actual in-service date, which is expected to be July 1, 2013. The deferrals would continue until rates become effective for this proceeding, November 1, 2013. For purposes of this adjustment, the assumptions of the in-service dates are the same as for the underlying plant adjustment discussed above in the Snoqualmie Falls Hydroelectric

Redevelopment Project – **Adjustment-4**.

Q. Why does the Company include this adjustment in this proceeding?

A. PSE includes the estimated deferred costs of the Snoqualmie Falls Project to avoid having to carry the deferral until a subsequent rate case. The current PCORC proceeding provides the earliest opportunity for Commission consideration of the deferrals. The deferred costs in this pro forma adjustment are the estimated costs associated with the Snoqualmie Falls Project. This is the same timing and process that has been followed for all prior RCW 80.80.060 deferrals that have been approved in prior rate case proceedings.

Q. What is the proposed amortization period for the Snoqualmie Falls Project deferred costs?

A. PSE is proposing an amortization period of seventy-two months from the date the rates in this proceeding become effective.

Q. Is the length of the amortization period PSE is proposing commensurate with the length of amortization periods for deferrals of similar size that PSE has received approval of in prior proceedings?

A. No. The total estimated deferral balance for the Snoqualmie Falls Project is $13.5 million. PSE has typically received between two and four year amortization periods for deferrals of this size. However, there are three other new deferrals related to the addition or disposal of resources that PSE is seeking recovery of in this proceeding, **Adjustment-7** Baker Deferral, **Adjustment-9** Ferndale Deferral and **Adjustment-**

12 Sale of Electron, which I discuss in more detail below. Because of this, PSE has chosen a longer amortization period in order to accommodate the total deferrals PSE is requesting recovery of in this proceeding, rather than establishing an amortization period for each deferral separately. This approach allows PSE recovery of the deferrals it is allowed to make under RCW 80.80.060(6) and at the same time results in a minimized impact on the rate request in this proceeding.

Q. Please explain how the Snoqualmie Falls Project deferral was calculated.

A. Per **Adjustment 4**, the rate year plant balance for the Snoqualmie Falls Project is $301,060,534. However, PSE calculates the deferral using a deferrable plant balance of $287,101,234 which excludes the cultural, park and historical costs of $13,959,300. PSE included in its deferral estimates of the following categories related to the deferrable plant balance: 1) return on rate base calculated at PSE's authorized net of tax rate of return grossed up for income taxes, 2) depreciation expense, 3) property insurance, 4) a market power offset. The market power offset represents an offset for the value of the reduced market purchases resulting from the plant generation because current rates do not include any generation for the Snoqualmie Falls Project. The market power offset is calculated using the hourly market price of power included in PSE's current baseline rate authorized in the 2011 GRC multiplied by the estimated gross generation for each month. Recognition of this market power offset provides the customer a reduction for the value of the Snoqualmie Falls Project generation not included in current rates. Because the Snoqualmie facility is connected directly to PSE's system and designated as a PSE network resource, no transmission reservations are required and thus there are no incremental transmission costs that require deferral.

To determine the impact of this adjustment on expense and rate base, the estimated deferral of monthly fixed costs and rate base return was accumulated from the actual and estimated in-service dates through October 31, 2013. This amount was then amortized over six years. The resulting amortization of $ 2,248,649 shown on line 12 of the adjustment is the impact of this calculation on expense before applying the production adjustment factor.

The rate base portion of the adjustment is the AMA of the deferred costs during the rate year net of the AMA of the accumulated amortization expense described above and the AMA of the deferred taxes associated with this deferral. As a result of this adjustment, rate base is increased $ 8,038,920 shown on line 28 of the adjustment before applying the production adjustment factor.

6. **Baker River Hydroelectric Project Relicensing Upgrades ("Baker Project") – Adjustment-6** presents the rate base and expenses associated with the Baker Project. The Baker additions include the Lower Baker Floating Surface Collector ("FSC"), which went into commercial operation on February 14, 2013, and the Lower Baker Powerhouse, with commercial operations expected to begin on June 10, 2013. The plant balance of $160,480,841 shown on line 2 of this adjustment represents the adjusted rate year plant cost for the project.

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

A. To calculate the investment for the Lower Baker FSC and the Lower Baker

Powerhouse, costs were estimated for construction through each in-service date, February 14th 2013 and June 10, 2013 respectively. Using the sum of these capital outlays, the AMA plant balance was calculated for the rate period. To calculate the depreciation expense, the depreciation rate of 2.19 percent was applied, which represents the average deprecation rate of both projects based on their individual in-service dates and the remaining period left on the Baker River Hydroelectric Project License. PSE received the fifty year license from FERC in October 2008. The depreciation expense was accrued monthly in this calculation, and the resulting monthly accumulated depreciation was averaged in the same manner as the plant cost.

As in the case of the Snoqualmie Falls Project, accumulated deferred taxes associated with the tax depreciation of the Baker Project were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(1)-1(h). For the Baker Project, the deferred tax calculation is based on twenty-year tax depreciation with the additional half-year Bonus Depreciation included in tax depreciation for the first year it is in service. Additionally, in December of 2010 FERC issued an order certifying that the Lower Baker Powerhouse qualifies for a Section 1603 Treasury Grant, which results in a reduction to the tax basis. This is discussed further in Mr. Loreen's prefiled direct testimony, Exhibit No. ___(DSL-1T).

After applying the half-year convention for tax depreciation, and recognizing the 50 percent bonus tax depreciation in the first year and including the reduction to tax basis resulting from the Treasury Grant, the deferred tax liability for the Baker Project is $24,273,951 for the rate year, shown on line four of this adjustment. The total of all the Baker Project adjustments described above increases rate base by $132,658,867.

Q. Please describe the expense adjustment.

A. The calculation of total book depreciation expense of $3,520,644 representing the sum of line 11 and 12 are explained above. The depreciation shown on line 12 of this adjustment is primarily a result of the Treasury Grant, which is not tax deductible. Accordingly, line 13 represents the gross-up associated with this non-taxable portion of depreciation. The rate year power generation and production O&M costs associated with the Baker Project are supported by Mr. Odom and Mr. Mills in their prefiled direct testimonies, Exhibit No. ___(LEO-1CT) and Exhibit No. ___(DEM-1CT). As in the case of Snoqualmie, the Baker facility is connected directly to PSE's transmission system and as a result, there is no incremental transmission costs associated with the project additions. The property insurance expense for the Baker additions is included with **Adjustment-14** for Property Insurance expense. Property tax related to the Baker Project is expected to be tracked in a separate tariff Schedule 140, as is discussed in **Adjustment-13** and is therefore not included in this adjustment. The Baker Project expense adjustment increases expense for electric operations by $3,718,278.

7. **The Baker Project Deferral – Adjustment-7** pro forms in the estimated deferral for the Lower Baker Powerhouse. As with the Snoqualmie Redevelopment, under amended RCW 80.80.060(6) the Company may defer costs of hydroelectric generation projects producing incremental electricity as a result of efficiency improvements completed after March 31, 1999. On December 16, 2010 as a result of PSE's filing to obtain qualification to receive treasury grants, FERC granted PSE certification under the Energy Policy Act of 2005 section 1301(c) that these improvements have resulted in incremental generation.

Q. Why does the Company include this adjustment in this proceeding?

A. PSE includes the estimated deferred costs of the Lower Baker Powerhouse to avoid having to carry the deferral until a subsequent rate case. The current PCORC proceeding provides the earliest opportunity for Commission consideration of the deferrals. This timing and methodology is consistent with all RCW 80.80.060 deferrals that have been approved in prior rate case proceedings.

Q. What is the proposed amortization period for the Lower Baker Powerhouse deferred costs?

A. PSE is proposing an amortization period of six years from the date the rates in this docket become effective. The basis for proposing this amortization period is discussed under **Adjustment-5** Snoqualmie Deferral above.

Q. Please explain how the Baker Project deferral was calculated.

Per **Adjustment-6**, the combined plant balance for the Lower Baker FSC and the Lower Baker Powerhouse was $160,480,841. However, PSE calculates the deferral using only the Lower Baker Powerhouse plant balance of $102,186,383 to which the incremental generation and the project's renewable status are directly attributed. Costs associated with the Lower Baker FSC of $58,294,458 were excluded from the deferral. PSE included in its deferral estimates of the following categories related to the deferrable plant balance: 1) return on rate base calculated at PSE's authorized net of tax rate of return grossed up for income taxes, 2) depreciation expense, 3) property insurance, and 4) a market power offset.

The market power offset for a new resource is typically determined by pricing the output associated with the plant at the market power price assumed in the then-current baseline rate. In the case of the Lower Baker Powerhouse, no volume of generation will be specifically attributed to the unit, but rather the addition of the powerhouse will allow the Baker facility in its entirety to generate just above the pre-construction levels under the new licensing constraints which go into effect at the commercial operation date. Therefore, for purposes of calculating the actual market power offset for the deferral period for this filing, the Company determined the benefit of any incremental generation *over* what was authorized in the 2011 general rate case baseline rate, and priced it at the corresponding market price. For this adjustment, there are two months forecasted in the deferral period in which this occurs.

To determine the impact of this adjustment on expense and rate base, the estimated deferral of monthly fixed costs and rate base return from June 10, 2013 through October 2013 were accumulated. This amount was then amortized over six years. The resulting amortization of $733,170 shown on line two of the adjustment is the impact of this calculation on expense before applying the production adjustment factor.

The rate base portion of the adjustment is the AMA of the deferred costs during the rate year net of the AMA of the accumulated amortization expense described above and the AMA of the deferred taxes associated with this deferral. As a result of this adjustment, rate base is increased $2,621,084 before applying the production adjustment factor.

8. **<u>Ferndale Plant</u> – Adjustment-8** pro forms plant costs of the Ferndale Generating Station ("the Ferndale Plant"), which was purchased November 15, 2012. This adjustment calculates the rate base, which is equal to the original seller's cost less depreciation reserve, and in this case a positive acquisition adjustment recorded in FERC Account 114, plus depreciation, accretion and amortization expense. FERC requires the original owner's cost to be booked in Account 101, Utility plant in service and the associated seller's accumulated depreciation to be booked in Account 108, Accumulated depreciation. The Ferndale Plant also has a property lease that ends June 30, 2041. Per the Lease Agreement, the Ferndale Plant must be removed prior to the end of the lease and the land must be restored back to original condition before the plant was in existence. PSE intends to retire the plant at the end of 2039 and remove the plant and all facilities by the end of the lease. PSE is proposing to depreciate the Ferndale Plant over 27 years. A 27 year life equates to an effective depreciation rate of 1.38 percent per year and is applied to the original owner's construction cost of the plant. The acquisition adjustment is amortized, over the same 27 years, which results in a 3.69 percent annual rate. Mr. Odom discusses the depreciable life of the Ferndale Plant in his prefiled direct testimony, Exhibit No. ___(LEO-1CT). Also included in **Adjustment 8** are the Asset Retirements Costs ("ARC") and Asset Retirement Obligations ("ARO"). These amounts represent recovery of the costs of restoring the site back to original condition before the lease ends in 2041. The restoration costs net of salvage were based on two studies conducted for the previous owner: (1) for demolition of the Ferndale Plant, and (2) for remediation of the site, back to original condition after the plant has been demolished. These costs are then adjusted to test year amounts in the Production Adjustment, **Adjustment-23**. Mr. Mullally discusses the purchase of the Ferndale Plant in his testimony, Exhibit No. ___(MM-1HCT). The power costs and production O&M costs associated with the Ferndale Plant are included in **Adjustment-1** Power Costs adjustment and are supported in the testimony of Mr. Mills and Mr. Odom, Exhibit No. ___(DEM-1CT) and Exhibit No. ___(LEO-1CT).

The property insurance for Ferndale is included in the Property Insurance **Adjustment-14**. As discussed in more detail in **Adjustment-13** below, in Docket Nos. UE-130137 and UG-130138, PSE has proposed a tracker, Schedule 140, for recovery of property taxes. Therefore, property taxes are not included in this adjustment as it is assumed they will be tracked in separate tariff filing.

This adjustment increases rate base by $73,498,988 and expense by $3,174,547.

9. **Ferndale Deferral – Adjustment-9** includes the estimated rate year amortization expense and net rate base amount for deferred costs associated with the Ferndale Generating Station. On November 15, 2012 PSE filed a Notice of Intent to Defer Costs with the Commission under Docket No. UE-121843. The costs of the project, from the in-service date of November 15, 2012 to the date rates will become effective for this proceeding, November 1, 2013, will be deferred under RCW 80.80.060(6), which allows cost deferral for projects that meet the Greenhouse Gas Emissions Performance Standard. The Ferndale Generation Station meets this standard.

Q. Why does the Company include this adjustment in this proceeding?

A. PSE includes the estimated deferred costs of Ferndale Generating Station to avoid having to carry the deferral until a subsequent rate case. The current PCORC proceeding provides the earliest opportunity for Commission consideration of the deferral. The deferred costs in this pro forma adjustment are the actual and estimated costs associated with Ferndale Generating Station from the date of purchase until the beginning of the rate period. This timing and methodology are consistent with all prior RCW 80.80.060 deferrals that have been approved in prior rate proceedings.

Q. What is the proposed amortization period for the Ferndale Generating Station deferred costs?

A. PSE is proposing an amortization period of six years from the date the rates in this proceeding become effective. The basis for proposing this amortization period is discussed under **Adjustment-5** Snoqualmie Deferral, above.

Q. Explain how the deferral was calculated.

A. PSE calculates the deferral using a gross plant balance equal to the total project cost. PSE included in its deferral actual and estimated amounts of the following categories related to the Ferndale Plant 1) return on rate base calculated at PSE's authorized net of tax rate of return grossed up for income taxes, 2) operations and maintenance expense, 3) depreciation, amortization and accretion expense 4) property insurance, 5) PCA defined variable costs, and 6) a market power offset. The impact of this adjustment on expense and rate base represents the actual deferred amounts from November 15, 2012 through February 28, 2013 plus the estimated deferral of monthly fixed and variable costs net of the market power offset plus rate base return for March 1, 2013 through October 2013.

Included in the variable cost estimate are the Ferndale fuel costs along with the offsetting value of the reduced market purchases resulting from the operation of the plant ("market power offset"). The market power offset is calculated using the hourly market price of power included in PSE's 2011 GRC multiplied by the actual or estimated generation for each month. Because Ferndale is connected directly to PSE's system and is designated as a PSE network resource, no transmission reservations are required and thus there are no incremental transmission costs that require deferral.

The total deferral balance was then amortized over seventy-two months. The resulting amortization of $4,191,320 shown on line 2 of the adjustment is the impact of this calculation on expense before applying the production adjustment factor.

The rate base portion of the adjustment is the AMA of the deferred costs during the rate year net of the AMA of the accumulated amortization expense described above and the AMA of the deferred taxes associated with this deferral. As a result of this adjustment, rate base is increased $14,983,968.

10. **Remove Wild Horse Solar**- **Adjustment-10-** restates the test year and removes the effects of the solar project at Wild Horse. This power project is a demonstration project and the Company is not requesting recovery of the costs associated with it at this time. This adjustment decreases expense for electric operations by $ 493,216 and decreases rate base by $2,805,550.

11. **Remove Tenaska –Adjustment-11** removes the amortization and rate base return that were included for three months of the test period associated with the Tenaska Regulatory Asset that was approved in Docket Nos. UE-971619 and UE-031725. Since PSE's 2009 general rate case, the costs associated with the Tenaska regulatory asset were recovered in a tracker, Schedule 133. The rates for Schedule 133 were updated in April 2011 per Docket No. UE-110380 and were effective through December 2011. As of December 31, 2011 the regulatory asset was fully amortized and the Schedule 133 rate was set to zero. This adjustment decreases expense by $10,157,004 and decreases rate base by $1,213,374.

12. **Sale of Electron Project – Adjustment-12**

In March 2013, PSE and Electron Hydro, LLC. reached final terms with respect to an Asset Purchase and Sale Agreement for the sale of the Electron Project. The determination of the need to dispose of the project and the scenarios considered for its disposal are discussed in the prefiled direct testimonies of Paul K. Wetherbee, Exhibit No. ___(PKW-1CT) and Michael Mullally, Exhibit No. ___(MM-1HCT). Additionally, PSE will be filing an application with the Commission in the near term to dispose of the Electron Project. In the application, PSE will request approval to defer the unrecovered plant cost in FERC account 182.2 Unrecovered plant and regulatory study costs. This adjustment assumes the regulatory treatment that will be requested is granted and it seeks recovery of the resulting unrecovered plant costs. The date of sale assumed for purposes of this adjustment is July 1, 2013. If the actual date of sale differs enough to have a material impact on this adjustment, PSE will update this adjustment in the supplemental filing when it updates power costs.

To recognize the sale of the Electron Project assets, this adjustment removes the AMA of the Electron Project plant, accumulated depreciation and deferred income taxes from the test year production rate base and removes the test year depreciation expense as well. This results in a reduction to production rate base of $26,165,931 shown on line ten of the adjustment and a reduction to production depreciation expense of $5,002,008 shown on line two of the adjustment.

The adjustment also pro forms in the balance of the unrecovered Electron Project costs and amortization expense as a variable regulatory asset. The unrecovered Electron Project costs were calculated using the sale price less the estimated net book value of the plant net of deferred income taxes at the time of the sale, estimated to be July 1, 2013. While in service, the Electron project assets were depreciating based on a studied rate. As depreciation expense for Electron will continue to be included in PSE's rates, even after the assumed sale date of July 1, 2013, PSE will request in its application and has factored in this adjustment that this monthly depreciation expense is applied against the deferred unrecovered plant balance beginning July 2013 until rates become effective in this docket on November 1, 2013. This results in the deferred unrecovered plant balance totaling $10.8 million at the start of the rate year.

To determine the impact of the adjustment for unrecovered plant costs on expense, the $10.8 million balance of the deferred unrecovered plant costs at the beginning of the rate year is used. Consistent with the other new regulatory assets requested in this proceeding, PSE has used an amortization period of six years. The basis for proposing this amortization period is discussed in **Adjustment-5** Snoqualmie Deferral above. Accordingly, the total deferral balance has been amortized over seventy-two months. The resulting regulatory asset amortization of $1,801,776 shown on line three of the adjustment is the impact of this calculation on expense before applying the production adjustment factor.

The rate base portion of the adjustment associated with the unrecovered plant costs is the AMA of the deferred costs during the rate year, net of the AMA of the accumulated amortization expense described above and the AMA of the deferred taxes associated with this deferral. As a result of this adjustment, regulatory asset rate base is increased $6,441,348 shown on line 16.

The removal of property insurance for the Electron Project is included in the Property Insurance **Adjustment-14**. The removal of Production O&M is included in Power Costs **Adjustment-1.** The removal of property tax is not included in this adjustment and will be tracked in separate tariff filing, as I discuss in more detail in the next Adjustment.

13. <u>Property Taxes</u> – Adjustment-13

The property tax adjustment is currently being withheld from this filing pending the approval of the property tax tracker, which was requested in PSE's expedited rate filing ("ERF"), Docket No. UE-130137. If the property tax tracker is not approved in PSE's ERF proceeding, PSE will need to include this property tax adjustment in this proceeding. In the final calculation of the revenue surplus in this proceeding, property taxes are also removed from the current Baseline Rate so that the change in revenue requirement in this proceeding is not impacted by the property tax cost recovery methodology.

If this pro forma adjustment were included to restate test year property taxes for known changes in the levy rates and production plant balances for Montana, Oregon and Washington, the revenue requirement deficiency would increase by $1,826,139.

14. <u>Property Insurance</u> – Adjustment-14 removes the Electron Project property insurance; includes Ferndale property insurance, which was not present in the test year; adjusts property insurance for the Baker and Snoqualmie Falls projects; and restates the remaining production property insurance to current levels. The adjustment decreases expense by $27,061.

15. **<u>Bonneville Exchange Power</u> – Adjustment-15** trues up the production related regulatory asset, net of deferred federal income taxes, to its projected rate year AMA balance. The amount of the decrease to rate base of $4,934,805 was determined using the amortization schedule approved in prior rate cases. No adjustment to expense is necessary as the test year level represents the amortization expense that will exist in the rate year.

16 **<u>Regulatory Assets –White River Hydroelectric Project-</u> Adjustment-16** trues up the production related regulatory assets and liabilities, net of deferred federal income taxes, to their projected rate year AMA balances. The amount of the decrease to rate base of $1,968,603 was determined using the amortization schedules approved in prior rate cases. No adjustment to expense is necessary as the test year level represents the amortization expense that will exist in the rate year.

17. **<u>Plant Deferrals</u> - Adjustment-17** proforms rate base and amortization related to the plant deferrals associated with resources approved in prior proceedings to rate year levels, with one exception discussed below. The amount of the decrease to rate base of $4,233,981 and increase to amortization of $1,822,226 was determined using the amortization schedules approved in prior rate cases. Both the Goldendale and Wild Horse regulatory assets will be fully amortized prior to the start of the rate year.

<u>Lower Snake River Phase 1 ("LSR Phase 1") Deferred Cost UE-120287 Lines 5 and 13</u> –PSE's deferral for LSR Phase 1 under RCW 80.80.060(6) was approved for recovery over four years in the 2011 GRC. Since the actual deferral amount of $17.9 million

was less than the $18.3 million approved in PSE's 2011 GRC, the monthly amortization amount for LSR Phase 1 was adjusted from $381,716 to $374,970 effective with the rates approved in this proceeding on November 1, 2013 so the approved amortization period of 48 months starting May 2012, the effective date of the 2011 GRC, could be maintained. This adjustment brings rate base and expense to rate year levels based on actual deferrals and using the amortization period approved in the 2011 GRC. This adjustment decreases rate base by $277,145 and increases expense by $2,751,129.

18. **Capacity Payments on Westcoast Pipeline (FB Energy and BNP Paribus) - Adjustment-18** trues up rate base related to capacity payments made to PSE by FB Energy and BNP Paribus approved in UE-082013 and UE-100053. The amount of the increase to rate base of $1,259,169 was determined using the amortization schedules approved in prior rate cases. No adjustment to expense is necessary as the test year level represents the amortization expense that will exist in the rate year.

19. **Chelan PUD Contract Initiation Payments & Security Deposit – Adjustment-19** trues up rate base and amortization related to a security deposit and initiation payment made under the Chelan Public Utility District ("Chelan PUD") power sales agreement for the output of the Rock Island and Rocky Reach Hydroelectric Projects to rate year levels.

The rate base and amortization expense for this rate year adjustment is calculated by using the amortization schedules approved in PSE’s 2011 GRC. This adjustment decreases rate base by $10,487,985 and increases expense by $590,672.

20. **<u>Other Miscellaneous Regulatory Assets - </u> Adjustment-20** trues up rate base and amortization related to the following regulatory assets which were included and approved for recovery in prior rate proceedings.

1. <u>Colstrip Units 1 and 2- prepayment Line 2 and 14.</u> On March 21, 2007, PSE made a non-refundable reservation dedication payment of $5 million (PSE's share) to Western Energy Company ("WECo") that assured the coal sales by WECo are limited to an existing contract that expired on December 31, 2010. The new contract period began January 1, 2010 and expires December 31, 2019, at the earliest. This reservation dedication payment was booked to FERC 165, Prepayments. As ordered in the 2011 GRC, the reservation payment is being amortized over ten years. The rate base and amortization expense for this rate year adjustment is calculated by using the amortization schedule approved in PSE's 2011 GRC. This adjustment decreases rate base by $1,317,322 and decreases expense by $458,333.

2. <u>~~F~~ERC Part 12 Study Non Construction Costs UE-070074 - Line 3 and 15</u>. On May 28, 2008, the Commission issued its order allowing PSE to recover non-construction related regulatory study costs based on an amortization period of five years for the costs incurred between January 8, 2007 through December 31, 2010. The rate base and amortization expense for this rate year adjustment is calculated by using the amortization schedule approved in PSE's 2011 GRC. This adjustment decreases rate base by $143,253 and increases expense by $60,317.

3. <u>Contract Major Maintenance – assets and amortization on Lines 5 through 9 and Lines 17 through 22.</u> In the 2011 GRC, the Commission determined that PSE may not use test year amortization and deferrals for prepaid assets related to major maintenance accounted for under Accounting Standard Codification ("ASC") 908-360-25 (previously FASB Staff Position No. AUG-AIR 1, Accounting for Planned Major Maintenance Activities, September 8, 2006) ("AUG-AIR 1" or "ASC 908-360-25"). Accordingly, the adjustments on lines 5 through 9 and lines 17 through 21 remove from the test year the amortization and rate base associated with deferrals that will no longer exist in the rate year. PSE is expecting a hot gas path inspection at its Mint Farm Facility in April 2013 to be performed under an existing Long Term Service Agreement ("LTSA") with General Electric International, Inc ("GE"). Mr. Odom discusses the background of Mint Farm LTSA and the details of the expected event in his prefiled direct testimony, Exhibit No. ___(LEO-1CT). In Paragraph No. 321 of the 2011 GRC Order No. 08, the Commission indicates that PSE can file an accounting petition to address the rate recovery of major maintenance events that are accounted for under AUG-AIR 1. Accordingly, shortly before the filing this PCORC, PSE filed an accounting petition associated with this expected major maintenance. The adjustment on Lines 10 and 22 reflect the accounting treatment requested in the accounting petition. Specifically, the petition requests to:

(1) treat the deferred maintenance pre-payments made to GE associated with the April 2013 maintenance event as a regulatory asset on Exhibit D under

the PCA mechanism;

(2) begin amortizing the deferred amounts when rates in this proceeding go into effect;

(3) use the same amortizable life that would be used for AUG-AUR 1 accounting which will end with the next expected maintenance event. Based on historical experience and expected run times, the next event is expected to be April 30, 2016. This would result in an amortizable life of 36 months; and

(4) treat the rate base and amortization as a variable cost in the PCA mechanism.

If the accounting petition is approved as filed, the balance of the deferred major maintenance costs at the beginning of the rate year will be $1.9 million. To determine the impact of the adjustment on expense, the $1.9 million balance at the beginning of the rate year is used. The total deferral balance was then amortized over thirty-six months. The resulting regulatory asset amortization of $634,721 shown on line 22 of the adjustment is the impact of this calculation on expense before applying the production adjustment factor.

The rate base portion of the adjustment is the AMA of the deferred costs during the rate year net of the AMA of the accumulated amortization expense described above. There are no deferred taxes associated with this deferral, as the tax and book treatment are the same. As a result of this adjustment, regulatory asset rate base is increased $1,586,802, as shown on line 10.

The overall effect of this adjustment is to decreases rate base by $1,206,047 and decreases expense by $1,275,845.

21. **<u>Lower Snake River ("LSR") Prepaid Transmission and Deferred Carrying Charges</u>** **Adjustment-21** trues up rate base and amortization related to the LSR Prepaid Transmission Deposit with BPA as well as the deferred carrying charges on the deposit that were both approved for recovery in the 2011 GRC.

At its May 31, 2012 Open Meeting, the Commission issued its order and allowed PSE to transfer the balances of the LSR Prepaid Transmission and the associated deferred carrying charges to regulatory asset rate base.

The AMA balance of the $99.8 million transmission deposit to BPA is shown on line two of the adjustment. The format of the amortization schedule used to determine the rate year balance of this regulatory asset was the same as was used in the 2011 GRC. The amortization schedule is dependent on actual transmission credits that are received by PSE from BPA. These transmission credits were projected for the rate year and the resulting amortization schedule was used to determine the rate year balance of the regulatory asset. This adjustment decreases rate base by $1,947,726. Amortization expense on this regulatory asset occurring in the rate year increases operating expense by $2,544,442.

The $17.4 million original carrying charges on the transmission deposit are also included in rate base on line three and were calculated by using the amortization schedule approved in PSE's 2011 GRC. This adjustment decreases rate base by $2,630,505. Amortization expense on this regulatory asset in the rate year increases operating expense by $405,356.

22. **<u>Hedging Line of Credit</u> – Adjustment-22** pro forms in the commitment costs associated with PSE's line of credit for hedging. In Docket UE-060266 and UG-060267, the Commission approved recovery of costs associated with a line of credit supporting hedging transactions in the PCA and Purchased Gas Adjustment ("PGA") mechanisms. Interest expense and debt issuance amortization are allocated to gas or electric based on actual experience as to which energy portfolio used the line of credit. For this adjustment, a 59/41 percent split between electric and gas, respectively, was used and is based on an analysis of the electric and gas portfolios and how the line of credit has been utilized. In Appendix A, Commitment 24 to the Multiparty Merger Settlement Agreement in Docket U-072375, PSE agreed not to advocate for a higher cost of debt or equity capital as compared to what PSE's cost of debt or equity capital would have been absent Puget Holding's ownership. Therefore, PSE has been including in the PCA and PGA the fees and expenses for the hedging line of credit at pre-merger amounts until the time that the facility which existed at the time of the merger would have expired. This pre-merger facility would have expired on April 4, 2012. Therefore, since that time, PSE has been including the full cost of the post-merger facility in the PCA and PGA mechanisms. Additionally, PSE recently entered into a new hedging line of credit and the annualized cost of the new, lower cost facility is included in this adjustment. This adjustment reflects the difference between the pre-merger facility costs that existed in the test year and the cost of the new facility and decreases operating expense by $52,144.

23. **<u>Production Adjustment</u> – Adjustment-23** pro forms the production related rate base and expenses that have not been included in **<u>Power Cost</u> – Adjustment-1**. As with **<u>Power Cost</u> – Adjustment-1**, these costs are adjusted to test year levels using the production factor, the ratio of test year delivered load to rate year delivered load, so that the test year level of costs are collected in the rate year. The test year delivered load of 21,321,495 MWhs has been adjusted by the temperature normalization, a reduction of 113,565 MWhs, and is discussed in more detail below. Additionally, a pro forma adjustment has been made to remove the test year load for the Jefferson County Public Utility District No. 1 ("JPUD"), which totaled 292,349 MWhs. JPUD assumed responsibility for providing retail electric service in Jefferson County on April 1, 2013. PSE no longer provides retail electric service within its former service territory in Jefferson County and therefore will not experience this level of usage in the rate year. The resulting adjusted test year delivered load of 20,915,581 MWhs divided by the rate year delivered load of 21,288,639 MWhs results in a production factor of 1.752 percent. When applied to the production costs and rate base in this adjustment, it reduces rate base by $47,679,276 and expense by $2,837,305.

24 <u>Temperature Normalization</u> – **Adjustment-24** presents the adjustment to test year load for the difference in temperature between the test year and a normal temperature year. Because the test year was colder than normal, on average, this adjustment deducts 113,565 MWhs from the actual load after adjusting for system losses. This adjustment is required to determine normal delivered load in the test year, which is used in the production adjustment and is used in determining the

Power Cost Rate. This adjustment is also used to determine the normal delivered load for the rate spread in this PCORC filing. As discussed in the Prefiled Direct Testimony of Jon A. Piliaris, Exhibit No. ___(JAP-1T), this normalization adjustment has been calculated using the methodology that the Commission approved in the Company's last general rate case, the 2011 GRC.

25 Conversion Factor – **Adjustment-25** allows the operating expense deficiency to be grossed up for revenue sensitive items to determine the total revenue deficiency or surplus. The calculation of this conversion factor uses the bad debt percentage from the 2011 GRC, current annual Washington State utility tax and the Washington Utilities and Transportation Commission annual filing fee rates. The conversion factor used in this procedure is 0.954994.

IV. ADJUSTMENTS ATTRIBUTABLE TO THE ACQUISITION OF NEW AND UPGRADED GENERATING FACILITIES

Q. Are the capitalized costs of acquiring the Ferndale Generating Station and the Snoqualmie and Baker Projects subject to change?

A. The costs of the acquisition of Ferndale that I described in detail under **Adjustment-8** above are known. For purposes of the PCA calculation following the implementation of any rate change from this proceeding, it is proposed that there not be any true up on the Ferndale capital costs.

The total project costs used for the Snoqualmie and Baker facilities discussed in **Adjustment-4** and **Adjustment-6** are based on projected cost at completion. To date, these projects are between 88% and 95% spent. Each of the projects has in-service dates that should allow most of the project costs to be known by the time of the supplemental filing in this case. However, if the Commission orders a true up of these costs to actual following the implementation of any rate change, PSE would follow the same procedures used in prior cases.

Q. Are there any other adjustments attributable to the acquisition of these three generation projects?

A. Yes, **Adjustment-5**, **Adjustment-7** and **Adjustment-9** present the cost of operating each plant from their respective actual or expected in-service dates to the date rates will be become effective November 1, 2013. The costs will be deferred under RCW 80.80.060(6), which allows cost deferral for projects that meet the greenhouse gas emissions performance standard or that are hydroelectric projects providing incremental generation due to efficiency improvements.

Q. What costs does the Company propose that the Commission approve in this proceeding with respect to costs of the Ferndale Generating Station, the Snoqualmie Falls Project and the Baker Project?

A. The following table summarizes the costs and rates that PSE is seeking Commission approval for the three generation projects in this proceeding.

Description	Ferndale	Snoqualmie	Baker
Utility Plant in Service			
Adj. No.	4.08	4.04	4.06
Gross Plant Balance (1)	$ 50,243,629	$301,060,534	$160,480,841
Average Remaining Service Life (Years)	27	31	46
Depreciation Rate	1.37%	3.19%	2.19%
Acquisition Adjustment			
Adj. No.	4.08	n/a	n/a
Total Acquisition Adjustment Balance	$30,992,513	n/a	n/a
Remaining Service Life (Years)	27	n/a	n/a
Amortization Rate	3.69%	n/a	n/a
Asset Retirement Cost			
Adj. No.	4.08	n/a	n/a
Total Asset Retirement Cost Balance	$1,564,370	n/a	n/a
Remaining Service Life (Years)	27	n/a	n/a
Depreciation Rate	3.69%	n/a	n/a
Asset Retirement Obligation			
Adj. No.	4.08	n/a	n/a
Total Asset Retirement Obligation	$4,712,117	n/a	n/a
Remaining Service Life (Years)	27	n/a	n/a
Accretion Rate	3.72%	n/a	n/a
Deferral			
Adj. No.	4.09	4.05	4.07
Total Estimated Deferral Balance	$ 25,147,918	$ 13,491,893	$ 4,399,023
Amortization Period (Years)	6	6	6

(1) Ferndale seller's gross plant at purchase was $134,878,099 less original seller's accumulated depreciation of $84,634,469 for a remaining plant balance of $50,243,629.

V. POWER COST RATE

Q. Please describe the impact of the pro forma adjustments on the Power Cost Baseline Rate.

A. Exhibit No. ___(KJB-5C) shows the impact of the above adjustments on the Power Cost Baseline Rate. This exhibit is prepared using the same methodology as Exhibit A to the PCA. *See* Exhibit No. ___(KJB-3). The costs are allocated between fixed and variable, and the total costs are adjusted for revenue sensitive items. The total costs of $1,279,737,645 are divided by the test year delivered load of 20,915,581 MWhs to calculate the new Baseline Rate of $61.186 per MWh before revenue sensitive items.

Q. Please explain the remaining pages included in Exhibit No. ___(KJB-5C).

A. The remaining pages of Exhibit No. ___(KJB-5C) are equivalent to the exhibits A-2 through D included in the PCA Settlement and have been updated to reflect the changes in power costs presented by PSE. Located on each page is the reference to the exhibit being replaced in the PCA.

Q. How will the new Power Cost Baseline Rate be implemented, given that the proposed rate year does not match the normal PCA period of January through December?

A. Each month the Company calculates the potential over or under collection of power costs for the PCA. For the fixed cost component of the PCA, these costs are attributed equally over the twelve month period. Once the new rate is approved, this part of the calculation will be changed to reflect the new monthly fixed costs allowed in the PCA for the remaining days and months of the PCA period.

Because the variable costs are adjusted to actual variable costs, there will be no change to the way this cost category is determined in the PCA calculation. Any necessary further adjustments required under the PCA mechanism will then be deducted from these costs.

The total of the above adjustments for an individual month will then be compared to the kilowatt hours for such month times the appropriate Power Cost Baseline Rate, and the algebraic sum of these variances for the PCA period will be the amount that will be considered in the sharing mechanism of the PCA.

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

VI. RATE CHANGE

Q. Please explain how the Company calculated the rate change required after taking into consideration the pro forma and restating adjustments.

A. As the Company is only requesting that the portion of its rates related to the PCA mechanism be adjusted using the power cost only rate filing, the required change in rates has been calculated using the difference between the Baseline Rate currently being used and the proposed Baseline Rate (each grossed up for revenue sensitive items). This calculation is shown in Exhibit No. ___(KJB-6) and, as shown on line 16, the new rate is $64.069 per MWh and the current rate is $64.099. As noted above, the current rate of $64.099 is the existing rate of $65.027 with property taxes removed and the calculation for this rate has been included in the work papers filed with my testimony. The difference between these two rates is multiplied by the normalized delivered load for the test period. The result of this calculation is the requested change in revenue surplus of $618,683 after revenue sensitive items. This change in rates results in an average decrease of approximately 0.03 percent.

Q. Please explain why the Company finds it necessary to decrease its rates by what appears to be a relatively small amount.

A. Although the revenue surplus may be regarded as small in an absolute sense, the shift between fixed and variable costs is significant. In order for the PCA mechanism to work as intended, not only should the rate year production expenses be as close as possible to what is expected in total dollars, but it is also essential that the fixed and variable components of the Baseline Rate be aligned in proportion to how costs will actually be realized. The net $618,683 surplus included in this Baseline Rate is comprised of a $51.0 million deficiency representing higher fixed costs resulting primarily from the new resources, offset by a $51.7 surplus representing lower variable costs associated with power costs. *See* the sixth exhibit to my prefiled direct testimony, Exhibit No. ___(KJB-7), lines 54 and 55. Additionally, it is beneficial to set rates so that PSE no longer needs to defer the costs of its new resources under RCW 80.80.060(6). Ultimately, however, PSE has invested in multiple beneficial production resources, the cost of which should be included in PSE's rates. The prudence of these resources is discussed in prefiled direct testimonies of Roger Garratt, David Mills, Paul Wetherbee, Michael Mullally and Aliza Seelig.

Q. Is the Company proposing to file for recovery of any power cost deferrals in this PCORC?

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.