EXHIBIT NO. ___(KJB-12T)
2013 PSE PCORC
WITNESS: KATHERINE J. BARNARD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of PUGET SOUND ENERGY, Inc. For an Accounting Order Authorizing Accounting Treatment Related to Payments for Major Maintenance Activities	**Docket No. UE-130583**
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	**Docket No. UE-130617**
In the Matter of the Petition of PUGET SOUND ENERGY, Inc. For an Accounting Order Authorizing the Sale of the Water Rights and Associated Assets for the Electron Hydroelectric Project in Accordance with WAC 480-143 and RCW 80.12.	**Docket No. UE-131099**
In the Matter of the Petition of PUGET SOUND ENERGY, Inc. For an Accounting Order Authorizing the Sale of Interests in the Development Assets Required for the Construction and Operation of Phase II of the Lower Snake River Wind Facility	**Docket No. UE-131230**

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

AUGUST 28, 2013

PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Are you the same Katherine J. Barnard who provided prefiled direct testimony and prefiled supplemental direct testimony in this docket on behalf of Puget Sound Energy, Inc. ("PSE" or "the Company")?

A. Yes, I filed prefiled direct testimony, Exhibit No. ___(KJB-1T), and six supporting exhibits, Exhibit No. ___(KJB-2) through Exhibit No. ___(KJB-7). I filed prefiled supplemental direct testimony, Exhibit No. ___(KJB-8T), and three supporting exhibits, Exhibit Nos. ___(KJB-9) through Exhibit No. ___(KJB-11).

Q. Please summarize the purpose of your rebuttal testimony.

A. My testimony discusses the various pro forma and restating adjustments that the Company is proposing in rebuttal. I present the uncontested adjustments between Commission Staff and the Company. I discuss specific restating and pro forma adjustments proposed by Commission Staff that are different from the Company's adjustment and explain why the Commission should adopt the Company's adjustment. In addition, I will respond to the following issues raised by Commission Staff:

1. Commission Staff's use of a different rate year than the one the Company

has used;

2. Commission Staff’s claim that PSE has used neither a test year nor a rate year, but has used an "adjusted test year" in calculating the Lower Snake River Phase I adjustment;

3. Commission Staff’s proposed April 25, 2013 "cut-off" date associated with the pro forma plant additions associated with the Snoqualmie hydroelectric redevelopment project (the "Snoqualmie Falls Project") and the Lower Baker hydroelectric plant (the "Lower Baker Project").;

4. The accounting and ratemaking treatment at issue in PSE's accounting petition related to payments for major maintenance activities under consolidated docket UE-130583;

5. Staff’s proposed adjustment to the regulatory asset associated with the Bonneville Power Administration ("BPA") large-generator interconnection agreement ("LGIA") carrying costs;

6. Commission Staff’s proposal for treatment of grants from the Department of Treasury under Section 1603 of the American Recovery and Reinvestment Act of 2009 (the "Treasury Grants") that the Company expects to receive associated with the Snoqualmie Falls Project and the Lower Baker Project.

Finally, I present the exhibits that support the PCA calculation during the rate year using the Company’s pro forma and restating adjustments for production and other power costs.

II. COMPARISON OF THE COMPANY'S REVENUE DEFICIENCY AND COMMISSION STAFF'S REVENUE DEFICIENCY

Q. Have you prepared a reconciliation between the revenue deficiency filed by the Company on July 2, 2013 and the current revenue surplus?

A. Yes. The following table highlights the differences, in thousands, between the Company's supplemental filing and the Company's rebuttal filing.

Description	Adjustment(s)	(Surplus) Deficiency (thousands)
Deficiency filed July 2, 2013		$ 491.9
Power Costs	14.01, 14.02	(6,725.0)
Snoqualmie Falls Project & Deferral	14.04 , 14.05	231.9
Lower Baker Plant & Deferral	14.06, 14.07	21.1
Ferndale Plant Deferral	14.09	(76.6)
Sale of Electron	14.12	5,380.7
Property Insurance	14.14	61.7
Other Reg A & L Misc	14.20	(168.0)
Other Reg A & L LGIA	14.22	(266.4)
Surplus filed August 28, 2013		$ (1,048.7)

Q. Did you prepare a reconciliation that shows the differences between Commission Staff's pro forma and restating adjustments and the Company's adjustments?

A. Yes. The first exhibit to my prefiled rebuttal testimony, Exhibit No. ___(KJB-13) provides a comparison of PSE's rebuttal filing revenue requirement surplus and

Staff's revenue requirement surplus from Exhibit No. ___(CTM-2), by adjustment. This comparison takes the difference of each party's baseline rates grossed up for revenue sensitive items and uses the current period delivered load to determine the revenue requirement for each adjustment.

III. RATE YEAR USED BY COMMISSION STAFF

Q. Do you agree with Staff Witness Christopher Mickelson's proposed change to the rate year?

A. No. PSE filed its PCORC on April 25, 2013, with a rate year beginning November 1, 2014. Commission Staff witness Mr. Mickelson proposes to change to a rate year beginning December 1, 2014. He attempts to justify this unusual change based on the additional month that was added to the procedural schedule at the prehearing conference. PSE agreed to this extension of the procedural schedule, as a courtesy, to accommodate the Commission's schedule. Mr. Mickelson's proposed revision to the rate year conflicts with other Staff witness' concerns about having adequate time to review the filing. Moving the rate year to start with December 1, 2013 would have required the Company to update almost every adjustment in its original filed case.

Q. Why did the Company "choose" a November 2013 through October 2014 rate year?

A. The Company's initial filing was made on April 25, 2013. Based on the six month suspension schedule approved in PSE's 2007 general rate case,[1] rates were anticipated to be in place by November 1, 2013. Therefore, the Company's filed rate year of November 1, 2013 through October 31, 2014 was reasonable.

Q. What events led to Mr. Mickelson's position that the rate year should be changed from the rate year in PSE's original filing?

A. Mr. Mickelson testifies that Staff changed the rate year to be consistent with the procedural schedule.

Q. Do you agree that the procedural schedule justifies a change to the rate year?

A. No. During the prehearing conference held on May 31, 2013, it was particularly difficult to establish a procedural schedule due to many conflicting obligations, including the Commissioner's availability and their request for a six-week period after briefs were due to deliberate prior to issuing a final order. Although all parties made considerable effort, there was no solution that would allow the rates to be effective on November 1, 2013 as anticipated, given the scheduling constraints presented at the prehearing conference. After much discussion and collaboration with all parties, and as a courtesy, PSE agreed to extend the rates' effective date to December 1, 2013 to accommodate the scheduling requirements.

Q. Did the parties discuss changing the rate year at the prehearing conference?

A. No, there was no discussion that agreeing to extend the procedural schedule and effective date for new rates would result in a change to the filed rate year and would require PSE to essentially refile its entire case to modify the rate year. Had there been such a discussion, it is unlikely PSE would have agreed to extend the procedural schedule.

Q. How burdensome would it be for PSE to change the rate year from the rate year in its prefiled case?

A. Changing the rate year would be very burdensome. It would require PSE to rerun its PCORC revenue requirement model and rework all of its revenue requirement work papers, as well as rerun its power cost model and Not in Models information and all supporting work papers, all of which are inputs to the revenue requirement model based on a rate year beginning December 1, 2013. For PSE to rerun its models and to provide recalculations of all adjustments with supporting work papers for a new rate year would require, at the very least, four weeks. It is equivalent to re-filing PSE's entire case.

Q. Did the change to the procedural schedule necessarily require rates to go into effect on December 1, 2013?

A. No. Based on past PCORC filings, the Company believed that the delay in the procedural schedule would not necessarily preclude rates from being effective

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[1] *See* Docket No. UE-072300, Order 13, ¶59 (Jan. 15, 2009).

November 1, 2013. One of the primary reasons that the procedural schedule was extended to December 1 was to allow for six weeks from the closing of the record to the time when rates would be effective. However, as discussed at the prehearing conference, should the parties reach a settlement, the need for the additional time in the schedule would likely not be necessary. Given that two out of the three PCORCs that have been filed since the inception of the PCA mechanism were fully resolved by settlements, the Company's assumption that the parties could reach settlement is not unreasonable.

Q. Why didn't the Company modify the rate year when it filed its supplemental testimony on July 2, 2013?

A. As previously discussed, PSE did not interpret the procedural schedule extension to require a complete re-running of its case using a new rate year, and no party requested PSE to refile its case with a new rate year as part of its supplemental filing. In the past, supplemental filings have updated power costs, they have never been used to change a rate year from the original filing. Moreover, PSE would expect that any such update to the rate year by the Company would be considered by parties essentially to be an entirely new filing and would have resulted in requests to delay the schedule further due to insufficient time to review the new case.

This assumption is not unreasonable, particularly when one considers that one of the modifications made in 2007 to the PCA/PCORC settlement agreement was to extend the proposed period from five months to six and to limit updates to allow for only one supplemental filing and one additional update at the time of the compliance filing if ordered by the Commission. In that proceeding, parties requested that modifications to the filing be limited in order to reduce the additional burden created for the parties to re-audit the results.

Q. Is Mr. Mickelson's expectation that the Company would modify the rate year consistent with other Staff witnesses?

A. No. Mr. Mickelson's expectation that the Company would modify the rate year is inconsistent with the testimony of Staff witness Williams, who indicates Staff requires "the full use of the time allowed by the procedural schedule to evaluate the adjustments without burdening the process, the record and the Commission's limited resources with later-filed evidence and updates".[2] To change the rate year to December 1, 2013 could have significantly delayed the proceeding and burdened not only PSE, but reviewing the revised adjustments within the procedural schedule would have burdened all parties.

IV. THE COMPANY'S CALCULATION OF THE LOWER SNAKE RIVER PHASE 1 ("LSR") ADJUSTMENT

Q. How do you a respond to Mr. Mickelson's testimony that by using an adjusted test year for the LSR adjustment PSE is using a different rate period for one asset?

A. I disagree with Mr. Mickelson's characterization of the LSR restating adjustment. PSE is following the established protocol from past general rate cases and

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[2] Exhibit No. __ (JMW-1T), page 12, line 21 through page 13, line 2.

PCORCs to adjust for a new plant that was not in service or in rates for the full historical test year. Mr. Mickelson confuses the issue by claiming that PSE is advocating for a different rate period for the LSR adjustment, when in fact PSE is applying a restating adjustment to the test year consistent with the Commission's rules and past practice. Mr. Mickelson ignores the fact that production rate base is set at test year levels, except for known and measurable adjustments associated with new production assets.

PSE's filing in this case adjusted the test period to reflect that it included only 8 months of actual balances associated with the LSR investment and therefore the costs needed to be restated to reflect the full 13 months necessary for the average of monthly average ("AMA") calculation. To accomplish this, PSE utilized balances from February 29, 2012, which coincides with the date LSR was put into service, through February 28, 2013.

Q. Has PSE's approach been used before?

A. Yes. PSE's adjustment follows the same procedures used in prior dockets where a generating plant that was approved for recovery in the preceding docket was put in-service during what has become a test year for a new proceeding. For example, this approach was used and approved by the Commission in PSE's 2005 PCORC (Docket No. UE-050870) where the Fredrickson 1 combined cycle facility was only in the test year results for 11 months of the test period. Similarly, in the 2007 general rate case, Docket No. UE-072300, the test year was restated for the Wild Horse facility which included only ten months of investment associated with the wind facility. For both of these plants, the full value of the new plant had been included in the revenue deficiency as a pro forma adjustment in the preceding docket when the plant was first brought into service. In the subsequent case, an annualizing adjustment was made for the plant for the period of time it was in-service, because the plant had not been included for the full test period. PSE's restating adjustment for LSR follows this same approach.

Q. Do you agree with Mr. Mickelson that the LSR restating adjustment does not conform to the Settlement Stipulations and past practice in prior PCORCs?

A. No. As discussed above, PSE used this same approach in the 2005 PCORC. I also disagree with Mr. Mickelson's conclusion that a restating adjustment for LSR violates the language of the PCA Settlement Stipulation. Mr. Mickelson points to language in the PCA Settlement Stipulation discussing the Fixed Rate Component of the PCA and how these components should be recovered in its baseline rate. The Settlement Stipulation addresses PCORCs in a separate section and does not address details of PCORC filings such as the use of restating adjustment.

V. SNOQUALMIE FALLS PROJECT AND LOWER BAKER PLANT

Q. Please summarize Commission Staff’s position regarding the production plant additions associated with Snoqualmie Falls Project and Lower Baker Project.

A. Commission Staff’s position as presented by Staff Witness Juliana Williams proposes to establish a cut-off date of April 25, 2013, for plant expenditures associated with the upgrades to the Snoqualmie Falls Project and the Lower Baker Project. The proposed cut-off date is the date of the Company’s initial filing. Additionally, Commission Staff proposes to exclude recovery of the deferrals associated with both the Lower Baker Powerhouse and Snoqualmie Plant 1 because those projects were placed in service after the cut-off date.

Q. Do you agree with Commission Staff’s position of using the initial filing date as a cut-off date for "known and measurable" plant investment levels?

A. No. Ms. Williams’s position is not consistent with past Commission Orders regarding new production plant and violates the matching principle by including the benefit of the low cost hydro generation in the power cost calculation while excluding portions of the costs of that plant merely because they occurred after the initial filing date. Additionally, her position is not consistent with the expressed preference of other Commission Staff witnesses to include the most updated costs in this proceeding.[3]

Q. Why do you believe Ms. Williams’s proposed cut-off date is inconsistent with past Commission orders?

Commission Staff's proposal to exclude all investments made after April 25, 2013 for PSE's hydroelectric facilities does not comport with the principle set forth by

[3] *See, e.g.*, Gomez, Exhibit No. ___CT(DCG-1CT) at page 11, lines 18-20.

the Commission that power costs should be set as closely as possible to costs that are reasonably expected to be actually incurred. The Commission articulated this principle in PSE's 2004 general rate case as follows:

> [P]ower costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings.[4]

In keeping with this principle, as recently as the 2011 GRC, the Commission included all of the costs associated with the LSR investment that was being placed in service just before the start of the rate year. The Commission stated in that case:

> Just as we allow updates for power costs during the pendency of a proceeding, even at the compliance stage, we also find it appropriate to allow PSE to update the capital costs of its investment in LSR-1 with more recent available data, considering the plant's February 29, 2012, in-service date, prior to the close of the record.[5]

Q. How do you respond to Ms. Williams's reliance on PSE's 2006 general rate case where she states the "Commission rejected plant additions"[6]?

A. Ms. Williams's testimony fails to recognize that the pro forma plant additions that were rejected in Docket UE-060266 were entirely related to transmission and distribution upgrades, not power production assets as is the case in this PCORC. Additionally, the proposal to add the transmission and distribution plant was made for the first time in rebuttal testimony, as an alternative to the Depreciation

[4] Docket Nos. UG-040640 & UE-040641, Order 06, ¶ 108 (Jan. 7, 2007).
[5] Docket Nos. UE-111048 & UG-111049, Order 08, ¶ 306 (May 7, 2012).

Tracker mechanism that had been proposed in that case. Although she is correct that the Commission rejected those transmission and distribution plant additions, in the same docket the Commission allowed a pro forma plant adjustment relating to the Wild Horse facility that was placed in service just prior to the beginning of the rate year.

Q. Why do you believe Ms. Williams's approach violates the matching principle?

If the Commission adopts Ms. Williams's approach, customers will receive the benefit of the energy generated from the Lower Baker Project and the Snoqualmie Falls Project during the rate year without paying the costs associated with the generation.

Ms. Williams recognizes her choice of a cut-off date is a "compromise"[7]. The Commission has not adopted a consistent practice in establishing a timeframe for acceptable pro forma adjustments. Although her attempt is to ensure that the plant amounts are known and measurable, her arbitrary and premature choice of a cutoff date—the April 25 filing date—is essentially ignoring the fixed costs associated with the low cost hydro generation, the benefit of which has been included in the rate year power costs. As discussed in the prefiled rebuttal testimony of Mr. Paul K. Wetherbee, Exhibit No. ___(PKW-16T), Mr. Mickelson

[6] Williams, Exhibit No. __ (JMW-1T), page 7, line 16 to page 8, line 7.
[7] Williams, Exhibit No. __ (JMW-1T), page11, line 11.

further exacerbates the matching principle violations with his proposal to exclude O&M costs associated with the operation of the facilities.

Q How do you respond to Ms. Williams's testimony that PSE "created" this situation by filing when it did?

A. Ms Williams's testimony implies the Company should have delayed its PCORC filing until the resources were entirely completed. However, based on prior Commission orders,[8] the Company purposely timed its filing to ensure that the new resources would be in service prior to the start of the proposed rate year, in part to minimize the amount of deferrals that would occur under RCW 80.80.060(6) and to better match cost recovery to the time a resource acquisition begins to provide benefits to customers.

Q. Do you agree with Ms. Williams's conclusion that PSE will not be harmed by the use of the April 25, 2012 cutoff date for production plant additions?

No, I do not. Ms. William's testifies that by including a portion of the costs and allowing the inclusion of the generating resources in the power cost models that PSE is not harmed because it will have another opportunity to update its costs in its next PCORC filing.[9] However, her assumption is incorrect. Inclusion of the resources in the power cost models results in a decrease in overall power costs because the variable costs associated with hydro generation from Company-owned facilities is virtually zero. As discussed in the prefiled rebuttal testimony

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[8] *See, e.g.,* Order 13 in Docket UE-072300, at ¶¶ 29, 55 (Jan. 15, 2009).

of Mr. David E. Mills, Exhibit No.___(DEM-8CT). inclusion of the forecasted power generated from the Baker and Snoqualmie projects, results in an increase of 264,115 MWhs from what is currently assumed in rates. At an average Mid C flat price of $32/MWh, this results in a lowering of power costs by approximately $8.5 million. Yet based on the project costs included in PSE's response to Staff Data Requests 43 and 46, excerpts of which are included in my Exhibit No. ___(KJB-18) and Exhibit No. ___(KJB-19), Ms. Williams's approach is excluding $28.3 million of projected investment. The return on, and return of, investment which is included in the fixed cost component, will be artificially lower than the actual costs and is effectively a 'disallowance' of those costs until they are incorporated into rates in the next proceeding.

Q. How do you respond to Ms. Williams's concerns regarding Commission Staff's ability to audit the costs?

A. I am perplexed by this testimony. PSE's initial filing relied entirely upon the estimated project costs. PSE's response to WUTC Staff Data Request Nos. 43 and 46 included updated expenditures and project information as of both April 25—the date of PSE's initial filing—and July 2, 2013—the date of the Company's supplemental filing. Therefore, at the same time Commission Staff received the data to review the expenditures through the initial filing date it also received the information to review expenditures through the supplemental filing date. At a

[9] Williams, Exhibit No. __ (JMW-1T), page 17, lines 6-13.

minimum, Ms. Williams should have utilized a July 2 cut-off date for costs associated with these generating facilities.

Q. Do you agree with Staff's choice to include only resources in service as of August 29, 2013 for inclusion in the power cost model?

A. No. As discussed earlier in my testimony Ms. Williams's approach of applying a cut-off date is inconsistent with prior commission orders regarding the inclusion of production assets. Commission Staff recognizes, and does not question that the Lower Baker Powerhouse was completed and began commercial operation in July 2013. As discussed later in my testimony both Snoqualmie Plant 1 and the parks and recreational projects associated with the FERC relicensing will be in service in early September, well before the start of the rate year.

Additionally, Staff's choice of the August 29, 2013 date is purportedly tied to the "discovery cut-off date in this proceeding"[10], however, according to the Prehearing Conference Order in this proceeding, discovery cut-off does not occur until September 18.

Q. Do you have any other concerns with Ms. Williams's approach?

A. Yes. Ms. Williams testifies that by including a portion of the costs and allowing the inclusion of the generating resources in the power cost models PSE is not harmed because it will have another opportunity to update its costs in its next

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[10] Williams, Exhibit No. ___(JMW-1T), page 13, line 12.

PCORC filing.[11] Ms. Williams's conclusion appears to be based, in part, on her understanding that costs not included in rates would continue to be eligible for deferral under RCW 80.80.060.[12] However, it is unclear whether the provisions of RCW 80.80.060(6) would allow for automatic deferral of those additional costs. The law specifically provides for automatic deferral of costs from the in service date until the plant is included in rates. By including a portion of the costs in rates, but not all costs, the Company is exposed to future legal challenges that continuing to defer unrecovered costs is not authorized under the law. At a minimum, if the Commission accepts Commission Staff's approach, it should expressly authorize PSE to continue deferring the additional costs of these eligible renewable resources in the same manner as allowed under RCW 80.80.060(6).

Q. How do you respond to Ms. Williams's proposal to delay[13] recovery of the deferred balances associated with Baker and Snoqualmie Plant 1.

A. Again, this seems to be a proposal that delays the recovery of costs associated with the upgraded generation facilities, where the benefit of the low cost generation output has been fully incorporated into the rate year power costs. Delaying recovery of the deferrals artificially understates the rates for the power costs to serve customers. Staff recognizes, and in fact does not question that the

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[11] Williams, Exhibit No. ___(JMW-1T), page 17, lines 6-13.

[12] WUTC Staff Response to PSE Data Request No. 2, included as Exhibit No.___(KJB-20).

[13] Based on WUTC Staff Response to PSE Data Requests Nos. 3 and 4, Staff is not challenging the eligibility of the costs for deferral under RCW 80.80.060(6), but merely the timing of the amortization of the deferral balances.

Lower Baker Powerhouse was completed and began commercial operation in July 2013, and that Snoqualmie Plant 1 and the parks and recreational will be in service by early September.

Q. Please summarize your recommendation regarding the treatment of the Snoqualmie Falls and Baker assets.

A. The Commission should reject Commission Staff's proposal to allow only known and measurable costs as of April 25, 2013, the initial filing date, for the Lower Baker Powerhouse and Snoqualmie Plant 1. Commission Staff has had an opportunity to audit updated costs and estimates and its Staff's adjustment is inconsistent with the most recent Commission precedent in PSE 2011 GRC, in which the Commission allowed PSE to update its costs for the LSR plant up through the date of commercial operations, which occurred on February 29—after the evidentiary hearing. In that case the Commission determined that "[t]his is the amount of investment that should be reflected in rate base."

PSE's proposed adjustment in this case reflects the updated budget for the Baker and Snoqualmie plants, as updated through June. Including these updated costs is consistent with Commission precedent and is a reasonable approach for these upgrades to Company-owned generation resources.

Additionally, as discussed in more detail later in my testimony, the deferrals and amortization expense associated with RCW 80.80.060(6) deferrals for the Lower

Baker Powerhouse and Snoqualmie Plant 1 should be approved and included in the baseline rate as proposed by the Company.

VI. MINT FARM: MAJOR MAINTENANCE COSTS

Q. Please provide a brief history of how the current accounting standards associated with major maintenance on turbines developed?

A. The current standards were developed originally for the airline industry. The airline industry needed an accepted and standardized method of accounting that matched the cost of maintaining aircraft turbines with the use of the turbines. AUG AIR-1, FASB Staff Position on Accounting for Planned Major Maintenance Activities ("AIR-1") listed the following acceptable accounting methods for accounting for planned major maintenance on turbines: the deferral method, the direct expense method and the built-in overhaul method. The guidance specifically prohibited the use of the accrue-in-advance methodology for tracking maintenance expense.

The definitions for the acceptable accounting methods listed above are as follows:

Deferral Method: Actual cost of each overhaul is capitalized and amortized to the next overhaul.[14]

Direct Expense Method: Costs are expensed as incurred since they are relatively constant from period to period.[15]

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[14] *See* ASC 908-360-30-3 and 35-6.

[15] ASC 908-360-25-2(a) and 908-720-25-3.

Built-in Overhaul Method: Costs are segregated based on those that should be depreciated over the useful life and those that require overhaul at periodic intervals.[16]

Q. Has AIR-1 become the accounting standard for tracking major maintenance on aircraft turbines?

A. Yes. The FASB has adopted this FASB Staff position in AIR-1 and the accounting standard is ASC 908-360-25. This is the standard that PSE was describing in Docket No. UE-130583. Mr. Mickelson points out in his testimony that the Company had listed ASC 980-360-25 as the standard. The petition was in error in that the 8 and 0 were transposed in the writing of the petition and this inadvertent error was not caught in review.

Q. Which of the AIR-1, or current ASC 908-360-25, methods does PSE use to account for its major maintenance expenses?

A. Historically, PSE has used two of the methods, the Deferral Method and the Direct Expense Method:

Deferral Method: PSE uses the Deferral Method to account for major maintenance performed on its combined cycle combustion turbine ("CCCT") parts that are covered under long term service agreements ("LTSAs") or contract service agreements ("CSAs"). Originally, the AIR-1 Deferral Method was

[16] *See* ASC 908-360-30-2 and 35-5.

adopted for this class of PSE’s thermal assets because the pattern of maintenance for PSE’s CCCTs is related to the run times or generation for these units that are used as base load plants. Additionally, PSE prepays its major maintenance under its LTSAs and CSAs and this payment pattern is commensurate for use in the AIR-1 Deferral Method. Later, I will refer to this method of accounting as the "Deferral Method".

Direct Expense Method: Historically, PSE has used the Direct Expense Method to account for all other major maintenance performed, the bulk of which is on its Pre-1990 vintage simple-cycle gas and oil-fired combustion turbines ("SCCTs"). The AIR-1 Direct Expense Method was originally adopted because the pattern of maintenance for PSE’s SCCTs, had been based upon time rather than generation. At the time of adoption of the accounting pronouncement, SCCTs were used to meet peak load demand. I will refer to these types of major maintenance expenses as "Direct Expense".

Q. Which AIR-1 method is used for the event included in PSE’s accounting petition filed under Consolidated Docket No. UE-130583?

A. The April 2013 Hot Gas Path inspection that was conducted on PSE’s Mint Farm Generating Station and which is the subject of PSE’s consolidated accounting petition is accounted for using the Deferral Method under AIR-1. At the time of the event, PSE had accumulated $1.9 million of prepayments to General Electric International, Inc. ("GE") which were accounted for under the Deferral Method.

Under the Deferral Method, PSE amortizes the deferrals to production O&M which is treated as fixed expense in the PCA mechanism.

Q. Please provide an overview of the rate making treatment PSE requested in the Consolidated Docket.

A. PSE had requested the following accounting and rate making treatment in its consolidated docket.

(1) treat the $1.9 million of 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 are approved and go into effect;

(3) use a three-year amortization period which is acceptable under the AIR-1 Deferral Method. Based on historical experience and expected run times, the next event is expected to be April 30, 2016; and

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

(5) otherwise, if the Commission is not agreeable to allowing amortization to commence with the effective date of new rates in this proceeding, then PSE requests that the amortization that began in June 2013 over a 36 month period under AIR-1 Deferral Method accounting be treated as variable cost in the PCA mechanism.

Q. Is PSE requesting to accrue interest on the deferred balance prior to its inclusion in rates as Mr. Mickelson states in Exhibit No. ___(CTM-1T), page 14 line 11?

A. No. PSE has not asked, nor does it intend to ask, to accrue interest on the unamortized balance.

Q. If the deferred balance were to be allowed to be accounted for as a regulatory asset and recovered through the PCA mechanism through inclusion on Exhibit D, would the unamortized balance of the regulatory asset earn a return?

A. Yes. This was PSE's original request in the consolidated docket.

Q. Was PSE's request in the consolidated docket consistent with Commission Staff's position in the 2011 general rate case?

A. Yes. In that proceeding Commission Staff argued that PSE should treat deferrals accounted for under the AIR-1 Deferral Method as a regulatory asset with their balances and amortization reflected at rate year levels, rather than at their test year levels.

> Staff argues that PSE's proposal is at odds with the agreed treatment in the PCA, under which the amortization expenses and balances of regulatory assets and liabilities are adjusted to rate year amounts consistent with other power cost expenses and rate base. Staff recommends that the costs of major maintenance under an LTSA or CSA should be treated similarly: rate year expenses and balances should be used for ratemaking purposes. Modifying the PCA, as the Company proposes, will introduce uncertain

> costs and create inconsistency with the existing regulatory assets and liabilities.[17]

Based on the above, PSE believed that requesting regulatory asset and rate base treatment was consistent with the recommendations of Commission Staff. Additionally, PSE believed that the issue it was addressing in its accounting petition comported with the Commission's directive that PSE not create a regulatory asset under blanket authority, but that it file an accounting petition to specifically request such treatment.[18]

Q. Does the position of Commission Staff witness Chris Mickelson in this proceeding appear to you to be consistent with Commission Staff's position from the 2011 general rate case?

A. No. Mr. Mickelson opposes PSE's request to treat the deferral as a regulatory asset. His adjustment removes the regulatory asset from rate base and the return on that asset from recovery.

Q. Does Mr. Mickelson propose recovery of the amortization expense associated with the deferral?

A. Yes, I believe his basis for including the amortization expense is that it is an expense that is known and measurable and that is accounted for properly under GAAP accounting. Therefore, it should be allowed for recovery in rates.

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[17] Docket UE-111048, Order 08, ¶ 317 (footnotes omitted).
[18] Order 08 at ¶ 321.

Specifically, Mr. Mickelson recommends "The appropriate accounting for major maintenance is to amortize these major maintenance costs following the time of the major maintenance event until the next major maintenance event, without earning a return on the unamortized balance for the expense. This is an acceptable method under generally accepted accounting principles ("GAAP")."[19]

Q. Do you agree with Mr. Mickelson's proposed rate making treatment of major maintenance expenses?

A. In part. The Deferral Method under AIR-1 stabilizes major maintenance expenses through amortization over the time between events. I agree with Mr. Mickelson's recommendation for recovery of the amortization expense on this post test year event as a known and measurable expense. As Commission Staff does recommend recovery of the amortization expense, I find acceptable Mr. Mickelson's proposal to not allow a regulatory asset and the associated PCA rate base treatment for major maintenance costs accounted for under the Deferral Method of AIR-1.

However, there is a caveat to PSE's agreement with Mr. Mickelson's proposal. If the AIR-1 Deferral Method balances are not regulatory assets, then the amortization expense should no longer be treated as variable regulatory asset amortization. The Company will follow standard accounting methodology and defer the maintenance costs, and the amortization expense should be treated as all

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[19] Exhibit No. ___(CTM-1T), page 13, lines 18-22.

other production O&M – consistent with how it is actually booked under FERC and GAAP accounting rules. Production O&M is a fixed cost in the PCA mechanism that has historically been included for rate recovery at test year levels, adjusted for known and measurable changes.

PSE requests that the Commission approve the AIR-1 Deferral Method as an acceptable accounting methodology for rate consideration in Washington. The amortization should be treated as fixed production O&M in order to avoid future conflict over the appropriate ratemaking treatment and will be set at test year amounts adjusted for known and measurable changes. In the context of a GRC or PCORC, the amortization schedules for events deferred under the AIR-1 Deferral Method that have amortization in the test year should be reviewed to determine if the schedules are fully amortized prior to or during the rate year. If they are fully amortized, the Commission should approve that their amortization be removed or restated accordingly. Additionally, the amortization expense associated with any post test year events that are known and measurable by the time of hearings in a given proceeding – like the April 2013 Mint Farm Hot Gas Path Inspection is in this proceeding – should be included in production O&M for recovery. In this way, events that are expiring (becoming fully amortized) have the opportunity to be replaced with the next known and measurable event. The Company believes this approach is consistent with the approach utilized by Mr. Mickelson in this proceeding, comports with accepted accounting procedures and appears to be consistent with the adjustments made by Mr. Martin in the 2011 General Rate Case.

Q. What other changes should the Commission approve associated with major maintenance accounted for under AIR-1?

A. PSE believes that the Commission should approve AIR-1 Deferral Method for rate making purposes for major maintenance performed on its gas fired turbines, including the SCCTs that are currently accounted for under the Direct Expense Method. This approach would be consistent with both Mr. Mickelson's testimony that states "the appropriate accounting for major maintenance is to amortize these major maintenance costs following the time of the major maintenance event until the next major maintenance event"[20] and the Commission's Order in the 2009 GRC where the parties all advocated and the Commission accepted in principle the use of the Deferral Method for major plant maintenance.[21] The Commission's explicit approval would provide the clarity necessary to defer and amortize all major maintenance events regardless of the type of gas fired turbine.

Under the Deferral Method, although major maintenance on SCCTs is not prepaid under a contract and therefore cannot be accrued prior to an event, the payment made at the time of the SCCT event would be deferred, and amortization would commence based on the time until the next event, consistent with the AIR-1 Deferral Method.

[20]Exhibit No. ___(CTM-1T), page 13, lines 18-21.
[21] Docket UE-090704, Order 11, ¶ 163.

Q. Why is it appropriate for the Commission to order that the AIR-1 deferral method be used for SCCT major maintenance expenses?

A. PSE elected the Direct Expense Method when it had a small fleet of SCCT that were used to supply energy during peak periods. When the SCCTs were used as peaking units, the time between major maintenance events was less predictable than on combined CCCTs, and therefore, there was not a reasonable basis to determine the time period over which to amortize costs. As discussed in Mr. Odom's prefiled rebuttal testimony, with the increase in starts and stops for these units necessary to support the renewable power plants in PSE's fleet, the use of these units has increased thus increasing the frequency of major maintenance events and the time between SCCT events has become more predictable.

Q. If the Commission were to approve the Deferral Method for all of PSE's gas fired generating units, would a regulatory asset be created?

A. No. The deferral balances that exist under GAAP accounting would not be a regulatory asset and therefore would be treated in a manner similar to other accounting deferrals. PSE would request recovery for the amortization that is booked to fixed production O&M in the test year, adjusted for known and measurable changes.

Q. Would PSE be guaranteed to recover its major maintenance expense under this requested treatment?

A. No. For events that fully amortize before or during a given rate year and do not have a replacement event occur in the appropriate time frame, PSE would not have amortization expense included in production O&M for the replacement event. As it is a PCA fixed cost, there would be no costs added to the PCA calculation prior to the next proceeding that changes power costs.

Q. Are there any other benefits associated with utilizing the Deferral Method for all major maintenance events associated with the natural gas fleet?

A. Yes, consistent use of the Deferral Method will provide a natural normalization of major maintenance expense and will remove the lumpiness associated with recognizing all the costs when the actual maintenance occurs. This creates a matching of costs with the actual benefit received from the refurbished turbine.

Q. Is the Company proposing that all maintenance associated with the natural gas fleet be deferred and amortized?

A. No, only those events that are considered major maintenance events which, consistent with Mr. Mickelson's definition,[22] typically occur when PSE overhauls or substantially upgrades various systems and equipment for purposes of maintenance or modernization.

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[22] Exhibit No. ___(CTM-1T), page 12 lines 20-23.

Q. Please summarize your rebuttal request related to major maintenance expense.

A. PSE requests that the Commission approve the use of the Deferral Method of accounting under AIR-1, or currently ASC 908-360-25, for setting rates. This accounting standard will apply to all major maintenance on all PSE owned gas fired turbines and the resulting accounting deferral will follow normal ratemaking considerations for similar accounting deferrals. The amortization of this accounting deferral will be treated as fixed production O&M in the PCA Baseline Rate and will be included in rates at known and measurable amounts. PSE agrees to amend its accounting petition to match the requested treatment outlined, or agrees to have the petition granted based on these modifying conditions.

VII. LSR STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT TRANSMISSION SERVICE CREDITS FROM BONNEVILLE POWER ADMINISTRATION AND ASSOCIATED DEFERRED CARRYING CHARGES

Q. Please provide an overview of the approved accounting for the LSR Standard Large Generator Interconnection Agreement Transmission Service Credits from Bonneville Power Administration ("BPA") and the associated Regulatory Asset for Deferred Carrying Charges.

A. As discussed in the prefiled rebuttal testimony of Mr. Roger Garratt, Exhibit No. ___(RG-7T), PSE entered into a standard large generator interconnection agreement ("LGIA") with BPA for the Lower Snake River Wind Facility. As part of the LGIA, PSE pre-funded $99.8 million to BPA for BPA to construct the Central Ferry substation. This pre-funding essentially functions as a loan from PSE to BPA. BPA operates, maintains, and owns the substation. BPA repays the "loan" to PSE by applying Transmission Service Credits plus an annual interest rate[23] in the form of additional Transmission Service Credits. These Transmission Service Credits are applied against the BPA transmission charges for the existing capacity of the LSR Phase 1 facility, currently 343 MWs. In other words, PSE receives "transmission service credits" equal to the total cost of the substation plus interest in the form of future transmission service from BPA. Docket No. UE-100882 is the original docket under which the existing accounting treatment was approved. The existing accounting treatment allowed PSE to accrue carrying charges[24] on the $99.8 million until the effective date of rates in the 2011 general rate case in which the $99.8 million of Transmission Credits were included in variable PCA rate base. In exchange for earning its authorized rate of return on the Transmission Credits, the accounting petition also approved that the LGIA interest received from BPA – which was based on the FERC interest rate or 3.5665% – would be provided to customers through a credit to account FERC 565 when received. As of May 14, 2012, which is the date new rates went into effect from the 2011 general rate case, PSE ratepayers have been

[23] Payments made by PSE to BPA prior to the execution of the LGIA accrued interest from BPA at the FERC interest rate; such rate was updated quarterly. Effective with the date of execution of the LGIA in June of 2010, BPA uses a fixed Bloomberg 10-year Treasury bond rate of 3.5665%, which does not change, to accumulate interest on all prepayments, whether those prepayments were made prior to or subsequent to the execution date.

[24] At the net of tax rate of return which was 7.00% through April of 2010 and 6.90% through May of 2012 grossed up for federal income taxes, or grossed up for FIT or 10.77% and 10.62%.

paying a return on the full $99.8 million associated with the loan made to BPA for the substation. PSE ratepayers have also been paying a return on $17 million in carrying costs that PSE accrued at its net of tax rate of return from May 20, 2010, through May 14, 2012. PSE is receiving monthly transmission credits from BPA, the interest portion of which is provided to customers, and PSE will continue to receive these credits for a 20-year period, at which time the outstanding balance of the loan including interest is repaid to PSE. The transfer of 21%[25] of the Transmission Service Credits to Portland General Electric ("PGE") allows the loan to be repaid quicker than if PSE were to rely solely on BPA Transmission Service Credit on the existing 343 MW capacity. In other words, if PSE were never to sell these Transmission Service Credits or if PSE were never to add additional capacity in the region through development of future LSR phases, PSE would eventually recover the full $99.8 million plus customers' BPA interest solely from its investment in Phase 1.

Q. What is PSE's proposal for the accounting and ratemaking treatment associated with the transfer of $20.5 million in BPA Transmission Service Credits to PGE?

A. As was summarized in my prefiled supplemental testimony, Exhibit No. ___(KJB-8T), under the terms of the contract, PGE will, after closing and within two business days after BPA's notice to PGE that BPA has completed its

[25] 21% is determined by dividing the 267 MW of capacity sold to PGE by the 1,250 total MW of original development rights for the entire LSR project.

process of assigning the transferred transmission credits to PGE, pay PSE an amount equal to $20.5 million in consideration of the transfer. My adjustment records this $20.5 million payment as a regulatory liability and accrues interest on it at PSE's authorized net of tax rate of return grossed up for federal income tax from the date of receipt until the beginning of PSE's rate year in this proceeding, or October 31, 2013. PSE anticipates that BPA will notify PGE of the assignment approximately two months after the transaction closing date which occurred in August 2013. Therefore, PSE expects to be in receipt of the payment from PGE on or about October 1, 2013. The monthly interest accrual is expected to be $175,000. Accordingly, I have included a $20,500,000 reduction of the $99.8 million principal balance effective September 30, 2013 and have reduced the accrued carrying charges regulatory asset by the $175,000 estimated return on the payment for the month of October.

Q. Does your proposal align with that of Commission Staff related to the $20.5 million received from PGE?

A. No. Commission Staff reduces the outstanding balance of the $99.8 million by the $20.5 million received from PGE as I have done, but their adjustment applies the reduction and begins accruing interest at PSE's net of tax rate of return grossed up for FIT in August 2013. The difference in the receipt date is that Commission Staff has assumed that the cash is received from PGE upon closing, despite the supplemental testimony I provided to the contrary. The Commission should adopt PSE's assumed receipt date, as it is more known and measurable than the August date assumed by Commission Staff, and, in fact, as of August 27, 2013, PGE and PSE are continuing to await notice from BPA regarding the transfer of the transmission credits and, accordingly, PGE has not yet made the $20.5 million payment to PSE.

Q. Please explain the other way in which Commission Staff's adjustment differs from yours.

A. Commission Staff argues that the regulatory asset for the accrued carrying charges should be reduced by $3.4 million which is equal to 21% of the unamortized balance of deferred carrying charges regulatory asset as of July 2013, the month prior to Commission Staff's assumed August 2013 receipt date. Commission Staff's adjustment essentially proposes a write-off or disallowance of the accrued carrying charges approved for recovery in PSE's 2011 general rate case.

Q. What is the basis for Commission Staff's $3.4 million disallowance?

A. Commission Staff believes that the regulatory asset associated with the accrued carrying charges on the LSR prepaid transmission should be reduced as a result of the transfer of the credits to PGE, claiming the $20.5 million "does not capture LSR Phase 2's share of accrued carrying charges".[26] Commission Staff did not provide evidence to support its position, and its only rationale is that, "generally, carrying charges become part of the initial balance of an asset. Therefore, when

[26] Exhibit No. ___T(JH-1T), page 11, line 4.

part of the asset is sold, the entire booked value associated with that part, including a share of the total carrying charges, should be removed from the Company's books of account."[27] Commission Staff further states that "PSE fails to take into account the fact that there are carrying charges associated with that $20.5 million."[28]

Q. Did PSE fail to take into account the fact that there are deferred carrying charges associated with the $20.5 million?

A. No. PSE has no similar adjustment to Commission Staff's disallowance because PSE does not believe that there should be a disallowance on the deferred carrying charges associated with the $20.5 million of transferred credits.

Q. Please explain.

A. As discussed in the prefiled rebuttal testimony of Mr. Roger Garratt, Exhibit No. ___(RG-7T), when PSE invested in Phase 1 of the LSR project, which added 343 MW of capacity, it entered into a Standard LGIA with BPA in order for BPA to construct the Central Ferry Substation to interconnect LSR to the BPA transmission system. The minimum option made available to PSE was for a 1,250 MW substation. There was no option for PSE to fund a substation for lesser capacity. Therefore, the full $99.8 million of prepaid deposits made under the LGIA by necessity relates to Phase 1 considering the prepaid deposits would be fully refunded through the application of the transmission credits against the

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[27] Exhibit No. ___T(JH-1T), page 12, lines 11-19.
[28] Exhibit No. ___T(JH-1T), page 13, lines 15-16.

BPA transmission charges associated with the 343 MW of capacity. PSE only transferred the credits to PGE in order to facilitate receiving reimbursement of the credits sooner than would have occurred utilizing LSR Phase 1 capacity alone. This benefits rate payers in that they will pay a lower return on the $99.8 million regulatory asset than they would absent the sale of the credits.

Q. Do you have concerns that Commission Staff's proposed disallowance on the deferred carrying charges of $3.4 million is calculated correctly?

A. Yes. Commission Staff's calculation fails to take into account the offset for the benefit of the BPA interest that has been credited to customers related to the time period over which the deferred carrying charges were accrued. This benefit amounts to $1.2 million[29] and would reduce the proposed amount of disallowance that has been calculated by Commission Staff.

Q. Should the Commission adopt Commission Staff's $3.4 million disallowance on the deferred carrying charges?

A. No, for the reasons I have stated above, the Commission should not adopt Commission Staff's $3.4 million disallowance on the deferred carrying charges.

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[29] $1.2 million is 21% of the $5.9 million of total BPA interest from Exhibit No. ___(JH-2), page 3, column g from May 2010 through April 2012, or alternatively, from column h from June 2012 through May 2013.

VIII. TREASURY GRANTS

Q. Please summarize your understanding of Mr. Mickelson's testimony regarding the proposed treatment of Treasury Grants associated with the Baker and Snoqualmie Projects?

A. Mr. Mickelson's proposal would pass back the Treasury Grants on the Snoqualmie Falls Project and the Lower Baker Project over the life of the plant ("LOP"), instead of over the ten-year period that the Commission approved in Docket UE-122001 only seven months ago. Mr. Mickelson would achieve this result by applying the Treasury Grants as an offset to the plant costs. I believe Staff's proposed accounting would be similar to a contribution in aid of construction ("CIAC").

Q. Do you agree with Mr. Mr. Mickelson's concern that intergenerational equity may exist if Treasury Grants are passed back over a ten-year period?

A. Yes. One of the specific issues that Mr. Mickelson raises is that of intergenerational equity. Hydro projects have very long lives; the current license for the Snoqualmie Falls Project is a 40-year license and the current license for the Baker River project is a 50 year license, each of which is the basis for the respective depreciable lives. By providing all of the tax benefit to ratepayers in the first 10 years, the early rate payers will receive all of the benefit of the Treasury Grant while the rate payers in years 11 through 40 or 50 will receive none. That does raise the issue of intergenerational equity, as Mr. Mickelson notes.

Q. What is the distinction between the Treasury Grants for LSR and Wild Horse Expansion wind farms and the Snoqualmie Falls and Baker hydro facilities?

A. The primary distinction between the wind farms and the Snoqualmie Falls and Lower Baker hydro projects is the amount of Production Tax Credits ("PTC") available for each facility. When PSE claimed the Treasury Grant on the wind farms, the math at the time showed that the Treasury Grant was roughly equivalent to the PTCs. Given this, Treasury Grants became the preferred option as they are an immediate cash payment and the benefit does not require the Company to have taxable income. In order to benefit from a tax credit, like the PTCs, a taxpayer must have a tax liability against which the credit can be applied.

Since the PTC was provided to taxpayers over the first 10 years of the projects life (based on generation), PSE requested (and the Commission approved) to match the pass through of the Treasury Grant to the life of the PTCs which it replaced. The idea was that customers in Years 1 through 10 would have benefited from the PTCs, and therefore they should receive the benefit of the Treasury Grants – therefore preserving intergenerational equity relative to the PTCs benefit.

Q. Are the Snoqualmie and Baker hydro projects eligible for PTCs?

A. Yes, PTCs are available for these projects but only on the incremental power that is produced. Because the incremental generation for each of these projects is relatively small, the value of the PTCs would also be quite small. This contrasts with the value of the Treasury Grant which is determined based on 30% of the eligible project costs and therefore is considerably larger than the PTC option. In terms of overall customer benefits, Treasury Grants were clearly the better option for the hydroelectric plants.

Since PTCs were not a viable option for hydro, there would be no reason – from a standpoint of equity – to limit the pass through of the Treasury Grants to ten years. If the pass back of the Treasury Grant is disassociated with the life of the PTCs, the next logical position would be to use the life of plant.

Q. Is the use of life of plant for these hydro projects most equitable, where PTCs are not a factor?

A. Yes, life of plant is a reasonable approach for these projects.

Q. Do you agree with Mr. Mickelson that PSE should defer the Treasury Grant associated with the Snoqualmie Project and the Lower Baker Powerhouse under RCW 80.80.060(6)?[30]

A. No. RCW 80.80.060(6) does not address Treasury Grants or authorize their deferral.

Q. Would you use the Treasury Grants as a reduction to the plant balance, similar to Contribution in Aid of Construction ("CIAC")?

A. No. This is where I disagree with Mr. Mickelson's approach. I would not use the Treasury Grant as a reduction to the plant balance. First, the Treasury Grant represents a discrete amount, similar to a regulatory asset or liability which needs to be passed back to customers. If the balance is applied to plant, it becomes subject to uncertainties associated with general rate making. More or less will be passed back to customers depending upon the timing of updates to plant. The underlying plant balance is of a different character entirely. It is not a static, dwindling balance. It is under constant refurbishment and maintenance. Capital expenditures are occurring regularly in order to maintain the plant in a state of perpetual readiness to perform its function.

The same cannot be said for Treasury Grants; they are one distinct amount that will never be refreshed. Nothing will ever be added to it and the balance will

[30] *See* Exhibit No. ___(CTM-1T), page 32, lines 1-6 and pages 33-34.

dwindle down to zero. Its life can never be extended because some maintenance or overhaul was performed.

Q. What is your second reason for disagreeing with Mr. Mickelson's approach?

A. Second, a tracking mechanism already exists, the Federal Incentive Tracker, therefore there is little incremental work required. There is nothing that would prevent including these Treasury Grants in the existing tracking mechanism and setting their amortization over the remaining life of their respective licenses.

Q. What are the benefits of using the tracker?

A. Using the tracker removes any possibility of under or over recovery of the Treasury Grant. The tracker will allow for completely accurate rate making as the unamortized balance will accrue interest at PSE's allowed rate. The tracker captures a wide range of federal incentives, and it will continue for a long time into the future as tax laws and federal incentives continue to shift and change. Any potential concerns around perceived inconsistencies in assignments of benefits to the various customer classes would be better resolved through rate design.

Q. Please summarize your testimony on the Treasury Grants.

A. The Company is open to Mr. Michelson's proposal to pass the Treasury Grants to customers over the life of plant, however, PSE believes that the refunding should continue to be provided through the Federal Incentive Tracker (Schedule 95A).

IX. UNCONTESTED ADJUSTMENTS BETWEEN THE COMPANY AND COMMISSION STAFF

Q. Have you prepared exhibits that detail the updated restating and pro forma adjustments that the Company is proposing in rebuttal?

A. Yes. Exhibit No. ___(KJB-14) summarizes the Company's restating and pro forma adjustments. This exhibit is presented in the same format as my Exhibit Nos. ___(KJB-4) and (KJB-9) and Mr. Mickelson's Exhibit No. ___(CTM-2). Exhibit No. ___(KJB-14) presents similar information as Exhibit Nos. ___(KJB-4) and ___(KJB-9) in this proceeding, after being updated for the revisions described in this prefiled rebuttal testimony. The first column in this exhibit provides the rate base and production costs from the test year that will be considered in setting the Power Cost Baseline Rate. Amounts in this column have not changed since the supplemental filing. The columns to the right of this first column show the impact of the pro forma and restating production cost adjustments PSE is proposing in rebuttal for the pro forma rate year. For the adjustments that have changed since the July 2, 2013 supplemental filing, the columns have been marked as "**REVISED**".

Each adjustment is presented in more detail on the succeeding pages referenced in the title of a particular column. 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 three of Exhibit No. ___(KJB-14). This column represents the costs included in determining the Power Cost Baseline

Rate, which is then used to calculate the required rate increase. These are the same amounts shown in the first column of Exhibit No. ___(KJB-15), "Exhibit A-1 Power Cost Baseline Rate".

The work papers supporting the April 25, 2013 adjustments were provided to Commission Staff and interveners on April 25, 2013. The work papers supporting the July 2, 2013 supplemental filing were provided to Commission Staff and interveners on July 2, 2013. For each adjustment that is marked "**REVISED**" in Exhibit No. ___(KJB-14), a new set of hard copy work papers has been prepared. A full set of electronic work papers for all adjustments, regardless of whether or not they are different from the supplemental filing, will be provided to Commission Staff and intervenors. The numbers that changed on each work paper lead sheet as a result of this rebuttal filing have been identified within the work papers.

Q. Please identify the adjustments in which the Company is in agreement with Commission Staff.

A. As originally filed or after making changes on rebuttal, the following adjustments are uncontested between PSE and Commission Staff:

Adjustment 10 – Remove Wild Horse Solar
Adjustment 11 – Remove Tenaska
Adjustment 13 – Property Taxes
Adjustment 14 – Property Insurance
Adjustment 22 – Hedging Line of Credit
Adjustment 24 – Temperature Normalization

Adjustment 25 – Conversion Factor

Q. Is this list of uncontested adjustments different than the list of uncontested adjustments that Mr. Mickelson presents in his prefiled response testimony?

A. Yes. PSE has agreed to the change that Commission Staff proposes for Adjustment 14 – Property Insurance. I discuss the details of this change more thoroughly later in my testimony. Additionally, I am unclear why Adjustment 22 – Hedging Line of Credit would be contested because of differing rate years. This adjustment annualizes the facility costs associated with the most current hedging facility. Even if a different rate year is assumed, there would be no change in the annual facility costs since the calculation is based on the existing facility arrangement – and as such there is no new information available that would change the calculation by rolling the rate year by one additional month. The same annualized cost would result either way. Finally, I have confirmed, via email with Commission Staff, that Adjustment 24 – Temperature Normalization should not have been considered as contested, and so I have reflected it as an uncontested adjustment.

X. CONTESTED ADJUSTMENTS

Q. Which adjustments are contested solely due to the difference between the rate year used by PSE and that used by Commission Staff?

A. The following adjustments are contested solely due to the different rate years used by PSE and Commission Staff. I discussed the rate year issue earlier in my testimony. PSE requests that the adjustments listed below be approved by the Commission based on the amounts reflected in Exhibit No. ___(KJB-14):

Adjustment 15 – Bonneville Exchange Power
Adjustment 16 – White River Regulatory Asset
Adjustment 17 – Plant Deferrals
Adjustment 18 – Capacity Payments on Westcoast Pipeline
Adjustment 19 – PUD Contract Initiation Payment and Security Deposit

Q. Would you please describe the difference between the Company and other parties on the contested adjustments?

A. Yes. The impact on operating expense and rate base for each of the Company adjustments is summarized on pages 4 through 30 of Exhibit No. ___ (KJB-14). Each of these adjustments is explained by reference to the actual adjustment page as listed below. The Company requests that the Commission accept the following adjustments as presented by the Company.

1. **Adjustment 14.01 – Power Costs –** were updated to reflect the power cost changes discussed in the prefiled rebuttal testimony of David E. Mills, Exhibit No.___(DEM-8CT). Mr. Mills' prefiled rebuttal testimony describes the changes to the Company's power costs and addresses the power costs proposed by Staff and ICNU. Unlike Staff's proposal, the rate year in the AURORA model and in the Not in Models assumptions has not been extended through November 30, 2014. In addition to conventional updates including those for gas prices, Mr. Mills discusses the removal of the Electron PPA, the inclusion of Electron operated as one of PSE's owned resources, updates for BPA's 2014 rate case, and removal of Cedar Hills mark-to-

market. Additionally, production O&M was updated to reflect the production O&M changes discussed in the prefiled rebuttal testimony of L. Edward Odom, Exhibit No. ___(LEO-4CT) and Paul K. Wetherbee, Exhibit No. ___(PKW-16T). PSE includes Electron production O&M at half the amount of the test year as proposed by Staff witness Gomez. In addition to the adjustments to power costs and production O&M related to the removal of the Electron sale, later in Adjustment 14.12, I discuss the impact to rate base and operating expense once the Electron plant is added back to rate base. A summary of all adjustments related to removing the sale of Electron from the rate year will be presented in that section. Finally, as I discuss in more detail in Adjustment 14.20, I have transferred the amortization expense for the Mint Farm Hot Gas Path inspection from Adjustment 14.20 to this adjustment. The Subtotal and Baseline Rate amount reflected on page one of Exhibit No. ___(KJB-14) is now decreased by $140,162,552 for this adjustment.

2. **Adjustment 14.02, Montana Energy Tax** has been updated for the change to Colstrip generation resulting from the updated generation assumptions supported by Mr. Mills. The Subtotal and Baseline Rate amount reflected on page one of Exhibit No. ___(KJB-14) is now increased by $900,278 for this adjustment.

3. **Adjustment 14.03 – Lower Snake River Phase 1 –** As stated above, PSE does not agree with Staff Witness Mickelson's adjustment of using a rate year calculation for LSR Adjustment 14.03 instead of the Company's annualized

test year calculation. There is nothing in the Settlement Stipulation which supports his calculation. As discussed earlier in my testimony, in prior proceedings the Commission has allowed adjustments similar to the LSR adjustment proposed by PSE in this case. Additionally, the Company does not agree with Mr. Mickelson's change to the rate year. PSE's rate year ending October 2014 is appropriate. Commission Staff's rate year ending November 2014 should be rejected. The Company believes that the adjustment was correctly calculated in my original April 25, 2013 filing. The Subtotal and Baseline Rate amount reflected on page one of Exhibit No. ___(KJB-14) has not changed since the previous filings and remains increased by $35,452,003 for this adjustment.

4. **Adjustment 14.04 – Snoqualmie Falls Project Plant –** As discussed earlier in my testimony, the adjustments to rate base and expenses have been updated from the original and supplemental filing in order to reflect the updated costs and project estimates of the Snoqualmie Redevelopment Project as discussed by Douglas S. Loreen in PSE's Response to WUTC Staff Data Request No. 036, *in its entirety* without a cut-off date of April 25th as proposed by Staff. Exhibit No. ___(KJB-17) includes excerpts from PSE's response to WUTC Staff Data Request No. 036. Per Exhibit No. ___(KJB-19), which is an excerpt from PSE's Response to WUTC Staff Data Request No. 46, which I referenced earlier, an increase to the project estimate of $4 million was primarily related to equipment and startup controls on Plant 2 and the extended construction schedule and schedule mitigation on Plant 1. The

assignment of the total cost between projects has changed since the original and supplemental filing. The allocation of budgeted engineering costs to units of property has resulted in the re-alignment of the estimate to one that more closely mirrors the way the project costs will close to plant upon completion. Since the time the prefiled direct testimony of Douglas S. Loreen, Exhibit No. ___(DSL-1T), was presented in the original filing, the commercial operations date ("COD") for Plant 1 was moved out from the assumed July 1, 2013 date to the current estimated COD, September 5, 2013. The revised COD accommodates the final fit-up, start up, and commissioning of equipment and mechanical systems. The Subtotal and Baseline Rate amount reflected on page one of Exhibit No. ___(KJB-14) is now increased by $36,752,938 for this adjustment.

5. **Adjustment 14.05 – Snoqualmie Falls Project Deferral** – As discussed earlier in my testimony, PSE disagrees with Commission Staff that recovery of deferrals associated with Plant 1 should be excluded in this proceeding. Snoqualmie Falls Plant 1 is scheduled to go into service on September 5, 2013, before PSE's hearing in this case. As such, PSE’s deferral calculation assumes the total estimated cost of Plant 1, Plant 2 and the Diversion Dam using the budget estimate and new COD for Plant 1 as discussed above. This adjustment is calculated in the same manner as previous RCW 80.80.060(6) deferrals, including LSR, Mint Farm and Wild Horse Expansion deferrals in prior rate proceedings. The costs of the project are being deferred under RCW 80.80.060(6), which allows cost deferral for renewable resources like

the Snoqualmie Redevelopment Project, beginning with the date of commercial operation. The Subtotal and Baseline Rate amount reflected on page one of Exhibit No. ___(KJB-14) is now increased by $2,626,660 for this adjustment.

6. **Adjustment 14.06 – Lower Baker Plant –** As discussed previously, the adjustments to rate base and expenses have been updated from the original and supplemental filing in order to reflect the updated costs and project estimate of the Lower Baker Powerhouse as discussed by Douglas S. Loreen in PSE's Response to WUTC Staff Data Request No. 036 *in its entirety* without a cut-off date of April 25th as proposed by Staff. Exhibit No. ___(KJB-17) includes excerpts from PSE's response to WUTC Staff Data Request No. 036. Since the time the prefiled direct testimony of Douglas S. Loreen, Exhibit No. ___(DSL-1T), was presented in the original filing, there has been a $2.5 million increase to the project estimate since the previous filings, which is primarily due to modifications necessary for final turbine generator component fit-up and alignment, additional excavation for the tailrace, controls design changes to fully integrate the existing Unit 3 with the new powerhouse, and resolution of contractor change orders for increased scope related to the previously listed items. These changes extended the construction schedule and required additional contractor and PSE resources to resolve. Accordingly, the COD for the Lower Baker Powerhouse was moved out from the assumed June 10, 2013 date noted in the prefiled direct testimony of Douglas S. Loreen, Exhibit No. ___(DSL-1T), to the actual COD, July 25,

2013. The revised COD accommodated the final fit-up, start up, and commissioning of equipment and mechanical systems. Exhibit No. ___(KJB-18) includes excerpts from PSE's response to WUTC Staff Data Request No. 043. The Subtotal and Baseline Rate amount reflected on page one of Exhibit No. ___(KJB-14) is now increased by $17,668,810 for this adjustment.

7. **Adjustment 14.07 – Lower Baker Plant Deferral -** As with the Snoqualmie deferral estimate, PSE disagrees with Staff that recovery of deferrals associated with the Lower Baker Powerhouse should be excluded in this proceeding because it went into service after the Company's original filing date. The Lower Baker Powerhouse has been in service since July 25, 2013. As such, PSE's deferral calculation assumes the total estimated cost using the updated budget estimate of the Lower Baker Powerhouse and the actual COD discussed above. This adjustment is calculated in the same manner as the previous RCW 80.80.060 deferrals, including LSR, Mint Farm and Wild Horse Expansion in prior rate proceedings. Additionally, corrections have been incorporated in the deferral calculations. These include corrections to the average of the monthly averages ("AMA") to include accumulated depreciation and deferred income tax, and to be based on the initial 13 months after the plant-in-service date. Finally, the calculation for the "Market Purchase Benefit" should reflect the benefit of any incremental generation on a cumulative basis as opposed to a month to month calculation as presented in the original and supplemental filing. The Subtotal and

Baseline Rate amount reflected on page one of Exhibit No. ___(KJB-14) is now increased by $724,327 for this adjustment.

8. **Adjustment 14.08 –Ferndale Generating Station** - The Company accepts Commission Staff’s proposal to update the discounted net present value of the Asset Retirement Cost and Asset Retirement Obligation ("ARC/ARO") to $1,562,307. The Company does not agree with Mr. Mickelson’s extension of the rate year from October 2014 to November 2014. The Subtotal and Baseline Rate amount reflected on page one of Exhibit No. ___(KJB-14) is now increased by $10,739,145 for this adjustment.

9. **Adjustment 14.09 – Ferndale Deferral –** The Company agrees with Staff’s removal of property taxes in light of the Commission’s final order in the Company’s request for an Expedited Rate Filing ("ERF"), Docket UE-130137. Additionally, the Company accepts Staff’s proposal to update the discounted net present value of the ARC/ARO to $1,562,307. However, the Company believes that the rate base components in Staff’s calculation were not treated consistently. In Staff’s computation of the rate base average of the monthly averages ("AMA"), the balances of the plant, accumulated depreciation and accumulated deferred FIT were calculated using the first 13 months of service, while ARC/ARO balances were calculated using the 13 months ended November 30, 2014, the end of the Staff’s proposed rate year. Because it was not available, Staff also omits the market power offset amount for the month of November of 2013, the last month of Commission Staff's

proposed deferral period. The Subtotal and Baseline Rate amount reflected on page one of Exhibit No. ___(KJB-14) is now increased by $5,657,224 for this adjustment.

10. **Adjustment 14.12 – Sale of Electron** – As discussed in the prefiled rebuttal testimonies of David E. Mills, Exhibit No.___(DEM-8CT), Paul K. Wetherbee, Exhibit No.___(PKW-16CT), Roger Garratt, Exhibit No.___(RG-7T), and L. Edward. Odom, Exhibit No.___(LEO-4T), the Company is willing to accept Staff's position that the timing of the Electron PPA is uncertain. The Company believes that if the Commission decides to postpone the approval of the ratemaking treatment for the sale of Electron, the plant should be treated like other test year production plants and left in rate base at the historical test year levels. Accordingly and consistent with Staff's adjustment, the Company is excluding the sale of Electron and removing the associated regulatory asset and amortization which was included in the original and supplemental filings. The Company is also including the depreciation and return on rate base as a result of keeping the Electron plant in the test year rate base. PSE disagrees with Staff's inclusion of the *rate year* plant balance in rate base as opposed to the test year, as this convention is reserved for new resources. As a result of PSE's and Staff's application of plant balances from the different periods, rate base return and depreciation amounts do not agree. Also, as included in Adjustment 14.01 above and supported in the prefiled rebuttal testimony and exhibits of David. E. Mills, in addition to Staff's adjustment of replacing the Electron PPA with market power, which results in a $1.4 million reduction to

power costs, PSE also includes the benefit of operating the Electron plant as an owned resource which results in an additional $2.2 million reduction to power costs. The rate base return, depreciation and reduction to power costs as a result of operating the plant, are three adjustments in which PSE differs from Staff in its treatment of the removal of the Electron sale from the rate year. The table below depicts the total change to the revenue requirement from the supplemental filing, of removing the sale as proposed by the Company and by Staff, and the difference between each proposal.

Change from Supplemental: Removal of Electron Sale (Increase) / Decrease to Surplus	PSE Witness	PSE	Staff	Diff
		In Millions		
Remove PPA and Replace with Market Power	DEM	($1.4)	($1.4)	$0.0
Include Electron as Owned Resource	DEM	(2.2)		(2.2)
Production O&M	LEO, PKW	1.8	1.8	-
Depreciation	KJB	5.0	4.9	0.1
Amortization on Regulatory Asset	KJB	(1.8)	(1.8)	-
Property Insurance	KJB	0.1	0.1	-
Return on Plant in Rate Base	KJB	2.0	1.3	0.8
Decrease to Surplus for Removing Sale of Electron *		$3.5	$4.8	($1.4)
** Represents Change from Supplemental to Rebuttal Filing.*				

The Subtotal and Baseline Rate amount reflected on page two of Exhibit No. ___(KJB-14) is now $0 for this adjustment.

11. **Adjustment 14.14 – Property Insurance –** As discussed above the Company accepts Commission Staff's proposal to include Electron plant in rate base and in so doing, property insurance of $59,890 has been included here. The Subtotal and Baseline Rate amount reflected on page two of Exhibit No. ___(KJB-14) is now increased by $101,511 for this adjustment.

12. **Adjustment 14.20 – Other Regulatory Assets and Liabilities Adjustment** –As discussed earlier in my testimony, the Company accepts Staff's proposal

to remove the regulatory asset, and thus the rate base return, related to the balance of the prepaid major maintenance on the 2013 Mint Farm Hot Gas Path inspection. See line 10 on Adjustment 20, which is now $0. The Company also agrees with Staff that the amortization expense should be included for recovery. However, as discussed earlier, the Company proposes the operating expense be moved from regulatory amortization, Adjustment No. 14.20, and be included in production O&M in Adjustment No. 14.01. The amortization of $634,721 is included in the totals supported by Mr. L. Edward. Odom in his Exhibit No. ___(LEO-5). As depicted in my original and supplemental testimonies, Exhibit No. ___(KJB-4) Page 5 of 30 and Exhibit No. (KJB-9) Page 4 of 30, this amortization expense – which was included in the column labeled "Amort of Reg Assets" – was moved from Mr. Odom's total production O&M so that it could be included in the regulatory asset adjustment, Adjustment 20. Accordingly, my Exhibit No. ___(KJB-14), page 5 no longer reflects this reclassification to Adjustment 20, but leaves the $634,721 in total production O&M included in Adjustment 01, line 9. Additionally, my Adjustment 20 no longer includes the amortization expense, as it is included in Adjustment 01. The Subtotal and Baseline Rate amount reflected on page three of Exhibit No. ___(KJB-14) is now decreased by $2,198,014 for this adjustment.

13. **Adjustment 14.21 – LSR Large Generator Interconnection Agreement Transmission Service Credits from BPA and associated Deferred Carrying Charges –** As discussed earlier in my testimony, PSE disagrees

with Staff's proposal to disallow the deferred carrying charges associated with $20.5 million of transmission credits, which will be transferred to PGE. The calculation remains unchanged from the supplemental filing but is adjusted only to include updated transmission rates per the BPA Administrator's Final Record of Decision ("Final ROD") based on its 2014 Power and Transmission Rate Adjustment Proceeding ("BPA 2014 Rate Case"). The Subtotal and Baseline Rate amount reflected on page three of Exhibit No. ___(KJB-14) is now increased by $790,008 for this adjustment.

14. **Adjustment 14.23 – Production Adjustment**, is being updated to reflect the changes to the production related adjustments above. The Subtotal and Baseline Rate amount reflected on page three of Exhibit No. ___(KJB-14) is now decreased by $7,811,730 for this adjustment.

XI. ADJUSTMENTS PROPOSED BY OTHER PARTIES

Q. Have the parties to this case proposed other adjustments to the Company's operating results?

A. Yes. Mr. Schoenbeck on behalf of the Industrial Customers of the Northwest Utilities ("ICNU") proposes two adjustments to the revenue requirement. First, ICNU recommends capturing the BPA's Final ROD rates for the rate year which became available after the Company's initial filing. Adopting these rates will lower the revenue requirement in this proceeding by approximately $3.1 million. The Company has updated these rates and the decrease to power costs is included in Adjustment No. 14.01 and supported in the exhibits and work papers of David E. Mills as discussed above. Secondly, ICNU recommends reducing the pro-forma Colstrip O&M expense in the proceeding based on actual expenses for 2009 through 2012, resulting in an approximately $3 million decrease to revenue requirement. As discussed in the prefiled rebuttal testimony of L. Edward Odom (LEO-4T), PSE disagrees with this proposal. PSE is using the same methodology for determining production O&M for Colstrip as it used in the 2011 general rate case and the last PCORCs and general rate cases. PSE witness L. Edward Odom provides more detail regarding the appropriateness of the rate year budgeted O&M in his prefiled rebuttal testimony Exhibit No. ___(LEO-4T).

Public Counsel did not propose any adjustments to the Company's proposed revenue requirement.

XII. REVENUE CHANGE

Q. Have you prepared a new exhibit that calculates the Power Cost Baseline Rate for the PCA in light of the changes to the fixed and variable power costs described earlier?

A. Yes. Exhibit No. ___(KJB-15) is similar to Exhibit No. ___(KJB-5) and Exhibit No. ___(KJB-10) but reflects the updates discussed above, which are prepared in the same manner as Exhibit A to the PCA Settlement. *See* Exhibit No. ___(KJB-3) at page 15. On the first page of Exhibit No. ___(KJB-15), the costs included in the Power Cost Baseline Rate have been allocated between fixed and variable costs in the same manner as discussed in the PCA Settlement Agreement. Following the same methodology set forth in Exhibit A to the PCA Settlement, this result is then divided by the test year delivered load to calculate the new Power Cost Baseline Rate of $61.166 per MWh. Once approved by the Commission, this would be the Power Cost Baseline Rate used in tracking the PCA periods beginning with the date rates are effective in this proceeding.

Q. Please explain the remaining pages included in Exhibit No. ___(KJB-15).

A. The remaining pages of Exhibit No. ___(KJB-15) are equivalent to Exhibits A-2 through D included in the PCA Settlement and have been updated to reflect the changes in power and production related costs. In the upper left hand corner of each of these pages is the reference to the exhibit being replaced in the PCA.

Q. Please explain how PSE calculated the rate decrease required after taking into consideration the revised pro forma and restating adjustments.

A. The rate decrease was calculated in the same manner as the original filing. This calculation is shown in Exhibit No. ___(KJB-16), which is similar to my Exhibit Nos. ___(KJB-6) and ___(KJB-11). As shown on line 16 of Exhibit No. ___(KJB-16), the new rate is $64.049 per MWh, versus the rate currently in effect of $64.099. 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 revenue requirement surplus of $1,048,707 after revenue sensitive items. This change in rates results in an average decrease of approximately 0.05 percent.

Q. Have new rate spread and rate design exhibits been prepared for this revised revenue requirement surplus?

A. No. PSE will update the tariff pages and the exhibits that were supported by Mr. Jon A. Piliaris in the original filing during the compliance filing in this proceeding.

XIII. CONCLUSION

Q. Does that conclude your prefiled supplemental direct testimony?

A. Yes, it does.