EXHIBIT NO. ___(JHS-19T)
DOCKET NO. UE-060266/UG-060267
2006 PSE GENERAL RATE CASE
WITNESS: JOHN H. STORY

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-060266** **Docket No. UG-060267**

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

AUGUST 23, 2006

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Are you the same John H. Story who submitted prefiled direct testimony in this proceeding on February 15, 2006, and supplemental prefiled direct testimony in this proceeding on July 10, 2006, each on behalf of Puget Sound Energy, Inc. ("PSE" or "the Company")?

A. Yes.

Q. Please summarize the purpose of your rebuttal testimony.

A. My testimony discusses the various electric proforma and restating adjustments that the Company is proposing in rebuttal. First, I discuss the adjustments proposed by Commission Staff and other parties that the Company agrees with and has incorporated in its updated electric revenue requirement determination. Second, I discuss adjustments proposed by Commission Staff and other parties that are inappropriate and with which the Company disagrees.

Based on the proforma and restating adjustments proposed by the Company and presented in Exhibit No. ___(JHS-20), there is an electric revenue deficiency of $33,778,533. If approved, this would represent an average 1.97% rate increase.

Based on the proforma and restated power costs for the test year, I present revised exhibits for the Company's Power Cost Adjustment Mechanism that reflect the production related costs in the Company's revenue requirement. These exhibits represent the Company's proposed Power Cost Baseline rate that will be in effect commencing with the beginning of the rate year, January 1, 2007.

Finally, I discuss the other parties' concerns about PSE's proposed depreciation tracker for electric and natural gas service and why these concerns are unwarranted. I also present an alternative to the depreciation tracker for Commission consideration which is based on known and measurable additions to the Company's transmission and distribution system since the end of the September 30, 2005 test period. The revenue requirement for these additions would be $8,772,793 for electric operations and $3,546,087 for gas operations. This revenue requirement would increase the revenue deficiency shown above and the gas revenue deficiency provided in Mr. Karl Karzmar's prefiled rebuttal testimony, Exhibit No. ___(KRK-11CT). As discussed by Ms. McLain, these transmission and distribution additions are infrastructure replacements or upgrades that do not produce new revenues but were needed to help maintain system reliability for existing customers.

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

Q. Have you prepared a reconciliation between the revenue deficiency filed by the Company in its supplemental filing and the revenue surplus filed by Commission Staff?

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

PSE Supplemental Filing Revenue Deficiency	**$42,927,314**
Changes proposed by/agreed to PSE in Rebuttal:	
20.02 Revenues & Expenses	(432,853)
20.03 Power Costs	(3,298,353)
20.05 Tax Benefit of Proforma Interest	(55,216)
20.08 Misc Op Exp	114,486
20.10 Hopkins Ridge	(1,760,988)
20.12 D&O Insurance	29,050
20.16 Rate Case Expenses	(522,349)
20.20 Wage Increase	489,808
20.21 Investment Plan	7,994
20.23 Montana Corporate License Tax	(31,739)
20.26 Wild Horse Wind Plant	(3,735,874)
20.32 Production Adjustment	47,253
PSE Rebuttal Filing Revenue Deficiency	**33,778,533**

Additional changes proposed by Commission Staff:	
Actual Results of Operations (Rate of Return)	(43,376,945)
E.03 Power Costs	(23,459,345)
E.05 Tax Benefit of Proforma Interest	(1,555,406)
E.08 Miscellaneous Operating Expense	(4,375,034)
E.12 D&O Insurance	(529,782)
E.16 Rate Case Expenses	(321,659)
E.20 Wage Increase	(489,808)
E.21 Investment Plan	(7,994)
E.26 Wild Horse Wind Plant	260
E.27 Incentive Plan	(560,638)
E.32 Production Adjustment	199,246
Commission Staff Revenue Surplus	($40,698,572)

Q. What is the major difference between the Company's revenue deficiency and the Commission Staff's revenue decrease?

A. Although the Company agrees with some of the Commission Staff's adjustments, their proposal is in essence a cost of capital and power cost adjustment. The $40.7 million decrease recommended by Commission Staff includes an adjustment to reduce the weighted cost of capital by more than $43 million. As discussed by Mr. Valdman, Dr. Morin and Mr. Gaines, Commission Staff's proposed adjustment to capital structure and return on equity should be rejected by the Commission. Mr. Mills discusses the power cost adjustment and why specific parts of the power cost adjustments proposed in the Joint Testimony of

Commission Staff, ICNU and Public Counsel, Exhibit No. ___(JOINT-19T) ("Joint Testimony"), should not be accepted by the Commission.

III. UNCONTESTED ELECTRIC ADJUSTMENTS BETWEEN THE COMPANY AND COMMISSION STAFF

Q. Have you prepared an exhibit which details the updated restating and pro forma adjustments that the Company is proposing?

A. Yes. Exhibit No. ___(JHS-20) summarizes the Company's restating and pro forma adjustments. This exhibit is presented in the same format as my Exhibit No. ___(JHS-4), Exhibit No. ___(JHS-16) and Mr. Russell's Exhibit No. ___(JMR-2).

Q. Please explain the adjustments where the Company is in agreement with Commission Staff.

A. The adjustments and their impact on Net Operating Income (NOI) or rate base are:

Adjustment	NOI	Rate Base
Actual Results of Operations	$231,281,640	$2,513,582,619
20.01 Temperature Normalization	$7,424,007	
20.02 Revenues and Expenses	$218,656,441	
20.04 Federal Income Tax	$4,185,813	
20.06 Conservation	$11,852,001	($28,822)
20.07 Bad Debts	($1,044,352)	
20.09 Property Taxes	$383,183	

20.10 Hopkins Ridge	(9,389,305)	$147,154,987
20.11 Excise Tax & Filing Fee	($384,314)	
20.13 Montana Energy Tax	$8,557	
20.14 Interest on Customer Deposits	($227,184)	
20.15 SFAS 133	$592,392	
20.17 Deferred Gain/Loss on Property Sales	($18,149)	
20.18 Property & Liability Insurance	($288,833)	
20.19 Pension Plan	($2,565,770)	
20.22 Employee Insurance	($669,622)	
20.23 Montana Corporate License Tax	($167,307)	
20.24 Storm Damage	($197,617)	
20.25 Regulatory Assets/Liabilities	($2,887,461)	($54,943,645)
20.28 General Office Relocation	($1,644,955)	(3,139,603)
20.29 Other Amortization	$5,065,947	
20.30 Demand Response Program	$0	
20.31 Depreciation	$0	$0

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

A. Yes. There are two adjustments that Mr. Russell lists as uncontested that the Company has updated for changes in estimates or actual amounts. Although the adjustments are still done in the same manner, the impact of the adjustment has changed with the updated amounts. Mr. Karzmar discusses the differences between the Company adjustments and Commission Staff adjustments in his prefiled rebuttal testimony, Exhibit No. ___(KRK-11CT).

Q. Would you please identify the adjustments that are on Mr. Russell's uncontested adjustments list that are different in the Company's rebuttal exhibits?

A. Yes. The adjustments are 20.20, Wage Increase, and 20.21,Investment Plan.

Q. Do any of the adjustments listed as uncontested differ from the equivalent adjustment in the Company's supplemental filing?

A. Yes. **Adjustments 20.10, Hopkins Ridge Wind Plant** and **20.26, Wild Horse Wind Plant**, are different from the Company's supplemental filing. Mr. Russell proposed that the depreciable life for both Hopkins Ridge and Wild Horse be adjusted to 25 years instead of the depreciable life of 20 years used for Hopkins Ridge in prior regulatory proceedings. The Company does not object to using a 25 year depreciable life for purposes of this rate case. However, the Company is in the process of performing a depreciation study on all its plant and will present the results of that study in its next general rate case proceeding. The results of that study may support a depreciable life for wind plants different than the 25 years to which PSE is agreeing in this case.

Even though the Company has adjusted the Hopkins Ridge and Wild Horse adjustments to a 25 year depreciable life consistent with Commission Staff's proposal, we have not treated the Wild Horse adjustment as uncontested because there is one other difference between the Company and Commission Staff. I will explain this difference later in my testimony.

Q. Please continue to describe the uncontested adjustments which differ from the Company's supplemental filing.

A. Electric Adjustments 2.12, Revenue and Expenses has been updated for the adjustment proposed by Mr. Russell for the proforma increase of $433,000 in pole attachment revenues. The Company has reviewed the calculation of the increase and agrees that this adjustment has been properly determined and included in the revenue requirement. This adjustment now increases net operating income by $218,656,441 and is uncontested between the parties.

There has also been a change made to the gas revenue and purchase gas cost adjustment 2.01, which is discussed by Mr. Karzmar in his rebuttal testimony.

IV. CONTESTED ADJUSTMENTS

Q. Would you please describe the difference between the Company and Commission Staff on the contested adjustments?

A. Yes.

<u>Power Cost Adjustment 20.03</u>

Mr. David Mills' prefiled rebuttal testimony describes the differences between the Company's power cost adjustment and the power cost adjustment proposed by Mr. Schoenbeck, Mr. Lazar and Dr. Mariam in their "Power Cost Joint Testimony".

In addition to the power cost adjustments proposed in the Power Cost Joint Testimony, Mr. Russell removed the costs associated with one third of the $1.4

million Muckleshoot Indian Tribe settlement payment and removed the $3.8 million of operations and maintenance costs associated with the Baker River hydro plant that will be required when FERC approves PSE's relicensing application. Mr. Kris Olin's rebuttal testimony describes why both of these costs are appropriate operating expenses and should be included in test year costs.

Baker Relicensing Costs

Mr. Russell does state in his testimony that it would be appropriate to include the Baker River O&M costs at the time the Company receives the Baker Project FERC license. As discussed by Mr. Olin in his rebuttal testimony, it is expected that the license will be issued later this year, although it is difficult to determine when FERC will actually issue the license, and it may be issued during 2007. Because the costs associated with the relicensing are not disputed, and the license is expected no later than during the rate year, it is not necessary to disallow these costs for recovery in this case. The Company could true these costs up in the PCA based on the actual issuance date of the license in the same manner that it trued up the costs for Hopkins Ridge based on its actual in-service date.

Muckleshoot Settlement Payment

Mr. Russell recommends the Commission disallow the cost of the Muckleshoot Indian Tribe settlement payment, or in the alternative spread the cost over 5.4 years. The Company's proposed methodology of spreading the cost of the payment over three years is consistent with the treatment of settlement costs in the Company's 2004 general rate case. In that case, the Company had paid a settlement amount to the Oregon Department of Revenue that resolved a dispute on property taxes on the 3rd AC Transmission line that went back many years.

It is obvious that it is in the customers' and the Company's best interest to withhold a disputed payment that has a possibility of being litigated. If the Company were to make a disputed payment to a third party and then prevail in arbitration or the courts on the disputed claim, there is no guarantee that the other party would have the ability to make restitution. Commission Staff's position of disallowing the recovery of such costs when it does become necessary to pay them is not beneficial to the customers or the Company, because it will, in effect, require the Company to pay such costs when demanded. The Staff's proposed disallowance of this cost should be rejected.

The longer recovery period proposed by Staff if the Commission were to allow the cost is not justified based on prior Commission practice or the magnitude of the dollars that are being requested for recovery.

Mr. Russell also argues that the Company should not be allowed the cost recovery because, per his analysis, the Company was over-earning during the test period. I will address the flaws in Mr. Russell's argument that the Company was over-earning its allowed rate of return later in my testimony. Even if the Company had been earning more than its authorized rate of return during the test period, that is not an appropriate reason to argue for disallowance of costs that are prudently incurred to serve customers. In ratemaking, the rate of return is not a cap on what a Company may earn. On average, it is the measure of what one should expect the Company to be able to earn, and as an average one should expect the Company to earn both over its allowed rate of return and below its allowed rate of return.

The total power cost adjustment that is appropriate in this case decreases net operating income $194,190,197.

<u>Tax Benefit of Proforma Interest, Adjustment 20.05</u>

As stated by Mr. Russell in his prefiled testimony, this adjustment is not disputed as to methodology used in the calculation. The difference between the Company and the Commission Staff for this adjustment is based on the different rate base and weighted cost of debt proposed by the parties.

Based on the Company's weighted cost of debt and rate base, this adjustment reduces net operating income $2,391,139.

<u>Miscellaneous Operating Expense, Adjustment 20.08</u>

The difference between the Company and Commission Staff on this adjustment is the Baker Lake Relicensing ratebase and amortization amounts. As I pointed out above and as discussed by Mr. Olin in his prefiled rebuttal testimony, the Company expects to receive approval of this license from FERC by the end of the year. We have adjusted the ratebase amount to reflect an in-service date as of October 1, 2006 and included the amortization of this capital amount over 45 years. As I discussed above, it is not necessary to disallow these costs in this proceeding because the Company can true up the costs in the PCA based on the actual date the FERC license is issued.

The impact of the Miscellaneous operating expense adjustment is to decrease net operating income by $2,902,650 and to increase ratebase by $29,572,082.

Director and Officer Insurance, Adjustment 20.12

Mr. Karzmar discusses the difference between the Company and the Commission Staff for this adjustment. The impact of this adjustment is to decrease net operating income by $13,291.

Rate Case Expenses, Adjustment 20.16

Mr. Karzmar discusses the difference between the Company and the Commission Staff for this adjustment. The impact of this adjustment is to increase net operating income by $226,966.

Wage Increase, Adjustment 20.20

Mr. Karzmar discusses the difference between the Company and the Commission Staff for this adjustment. The impact of this adjustment is to decrease net operating income by $2,512,047.

Investment Plan, Adjustment 20.21

Mr. Karzmar discusses the difference between the Company and the Commission Staff for this adjustment. The impact of this adjustment is to decrease net operating income by $99,416.

Wild Horse Wind Plant, Adjustment 20.26

As I discussed earlier in my testimony, the Company does not object to changing the book depreciable life of Wild Horse from 20 years to 25 years for this case.

In the Company's supplemental filing of July 10, 2006, there were a few changes made to this adjustment which Commission Staff did agree with. Commission Staff reflected one of these adjustments in a different manner in their revised prefiled testimony and exhibits. A correction was made to the acquisition value of the Wild Horse Wind Plant and this correction was also made by Commission Staff. However, their correction was made in such a way that the plant was assigned a different tax life, which resulted in a $1,840 difference in the accumulated deferred federal income tax included in the ratebase component of this adjustment. This difference has been discussed with Commission Staff and it is my understanding that they are in agreement with the amounts reflected in the Company's adjustment. This adjustment reduces net operating income by $19,715,599 and increases ratebase by $356,220,868.

Incentive Pay, Adjustment 20.27

Mr. Karzmar discusses the difference between the Company and the Commission Staff for this adjustment. The impact of this adjustment is to increase net operating income by $690,180.

Production Adjustment, Adjustment 20.32

As stated in Mr. Russell's testimony, the production factor and the methodology used in calculating this adjustment are not disputed. The difference between the Company and Commission Staff on this adjustment is dependent on other adjustments related to production plant and production operating expenses. The impact of this adjustment is to increase net operating income by $787,513 and to decrease ratebase by $11,102,293.

Q. Does that complete your discussion of proforma and restating adjustments?

A. Yes, it does. No other parties to this case filed proforma or restating adjustments other than through joint testimony with Commission Staff.

Revenue Deficiency

Q. Would you please explain Exhibit No. ___(JHS-21)?

A. Exhibit No. ___(JHS-21) presents the calculation of the revenue deficiency based on the proforma and restating adjustments discussed above. As shown on page 1 of this Exhibit No. ___(JHS-21), based on $2,977,316,193 invested in rate base and $239,845,435 of net operating income, the Company would have an electric retail revenue deficiency of $33,778,533.

Cost of Capital

This schedule, shown on page 2 of Exhibit No. ___(JHS-21), reflects the proposed capital structure for the Company during the rate year and the associated costs for each capital category. The capital structure and costs are presented in the prefiled rebuttal testimony of Mr. Donald Gaines, Exhibit No. ___(DEG-7CT). The rate of return is 8.76%.

Conversion Factor

The conversion factor, shown on page 3 of Exhibit No. ___(JHS-21), is used to adjust the net operating income deficiency by revenue sensitive items and Federal income tax to determine the total revenue requirement. The revenue sensitive items are the Washington State utility tax, Washington WUTC filing fee, and bad debts. The conversion factor used in the revenue requirement calculation, taking into consideration the adjustments discussed earlier, is 62.07334% and is uncontested between the parties.

PCA Exhibits

Q. Please describe Exhibit No. ___(JHS-22C).

A. Exhibit No. ___(JHS-22C) presents the adjusted Exhibits for the Power Cost Adjustment mechanism. Page 1 of this exhibit adjusts Exhibit A-1, Power Cost

Rate, to reflect the new Power Cost Rate of $58.925 per MWh based on the Company's rebuttal revenue requirement calculations. The methodology applied is consistent with that set forth in the PCA Settlement Agreement, under Docket No. UE-011570, and the PCA Compliance Settlement Agreement, under Docket No. UE-031389.

Q. Does the Commission have the detailed information necessary to calculate the Power Cost Rate based on its final determination of the appropriate production ratebase and operating expenses to be included in rates?

A. The calculations used to determine the line items on Schedule A-1 are included in workpapers and not all of these workpapers would be included in the record. To ensure that these pages are accurate, it would be best for the Commission to have the Company recalculate these Exhibits based on the final Commission Order. The Company would then file the revised pages with the compliance filing required to implement the Commission's Final Order.

V. UTILITY OPERATIONS

Q. Have you reviewed Mr. Russell's Exhibit No. ___(JMR-5) and, if so, is it an accurate representation of the Company's return on total equity over the past four years?

A. I have reviewed Mr. Russell's Exhibit No. ___(JMR-5). It is not an accurate representation as to the Company's return on total equity.

Q. Would you please explain why it is not accurate?

A. Mr. Russell starts his calculation with the total PSE Utility Capital Structure as shown in each of the years 2002 through 2005. This information was taken from Exhibit 57 in the Company's 2004 general rate case for the years 2002 and 2003 and from PSE's Response to WUTC Staff Data Request No. 049 in this proceeding for the years 2004 and 2005. Mr. Russell then takes the net operating income from the Company's Commission Basis Reports for both electric and gas operations as a starting point to determine the return on equity earned for each energy operation. As return on equity has to be determined after interest costs, Mr. Russell properly takes the actual weighted average cost of interest on debt as shown on Exhibit No. ___(JMR-5) times the rate base for electric and gas and deducts the resulting interest calculation by energy type from its respective net operating income. Mr. Russell then calculates the equity associated with ratebase by taking the equity component of the actual capital structure in each year times the rate base for electric and gas. He then calculates the return on equity by dividing the net operating income minus interest by the equity component of rate base. He inappropriately assumes this is the return on equity the Company earns on its total equity and uses this percentage to determine the weighted cost of equity for the Company's total capital structure. This calculation is then added to the weighted cost of debt and preferred stock to determine the actual rate of return earned. To illustrate this I have recreated his calculation for 2002 in Exhibit No. ___(JHS-23).

Q. Why is this inaccurate?

A. The first problem with the calculation is that, by applying the return on equity calculated based on the equity in rate base to the total Company equity, Mr. Russell has assumed that the difference between the total equity for the Company and the equity imbedded in rate base earn the same return. He presents no evidence that this is true, and in fact it is not true. One example of why this is not true is that the Company is allowed to increase interest revenues associated with construction work in progress ("CWIP") through the Allowance for Funds Used During Construction ("AFUDC") calculation.. In this jurisdiction, AFUDC is calculated using the Company's allowed rate of return but the actual return is lower than the Company's allowed rate of return. AFUDC is another item, like interest, that is shown on the income statement after net operating income.

For the same years shown in Mr. Russell's Exhibit No. ___(JMR-5), the actual return earned on CWIP can be calculated by dividing the AFUDC booked to interest income by the average construction work in process during the year. This calculation is presented in the table below (dollars in million) and these results lower the return on total equity.

Year	AFUDC Income	CWIP (AMA)	Actual Return	Allowed Return
2002	$3.37	$122.73	2.74%	8.76%*
2003	$5.62	$134.28	4.18%	8.76%
2004	$8.22	$138.84	5.92%	8.76%
2005	$13.29	$217.55	6.11%	8.40%*

* The allowed rate of return shown for 2002 and 2005 in the above table was the allowed rate of return that became effective during the year based on Commission General Rate Case Orders that were effective during the year.

Q. Are there other problems with Mr. Russell's Exhibit No. ___(JMR-5)?

A. Yes. On page 22 of his prefiled response testimony, Exhibit No. ___(JMR-1T), Mr. Russell points out that in warmer years the Company had lower revenues and would have earned a higher return than what he has calculated because revenues would have been higher in a normal year. Mr. Russell only points out one of the adjustments in a Commission Basis report that might increase revenues. If adjustments are going to be made to the actual earnings to determine whether a Company is over or under recovering its rate of return, there are several adjustments that should also be made that reduce earnings. These include several financial reporting adjustments that increase net operating income, such as SFAS 133, Accounting for Derivative Instruments and Hedging Activities and SFAS 87, Employers' Accounting for Pensions, that are removed for ratemaking purposes. Also as I mentioned earlier, Mr. Russell deducted the interest associated with ratebase from net operating income; however, he left the tax benefit associated with all the Company's interest in net operating income. As this lowers current taxes payable, net operating income is overstated.

Q. Is the Company asking the Commission to offset regulatory disallowances through rate increases as stated by Mr. Russell on page 23–24 of his prefiled response testimony?

A. No.

VI. TRACKER MECHANISMS

A. Power Cost Adjustment Mechanism

Q. Were you involved in the development of the Power Cost Adjustment ("PCA") Mechanism that is currently in effect for PSE?

A. Yes. I was part of the Company team that worked on the development of the PCA Mechanism and testified as part of the joint panel in Docket No. UE-011570 that presented the PCA Mechanism to the Commission for approval. This joint panel consisted of the following:

(i) Mr. Jim Elsea and myself, on behalf of the Company, who adopted and presented the prefiled testimony of William A. Gaines describing and supporting the PCA settlement;

(ii) Mr. Mert Lott, on behalf of Commission Staff, who presented prefiled testimony describing and supporting the PCA settlement; and

(iii) Mr. Jim Lazar, on behalf of Public Counsel, who presented prefiled testimony describing and supporting the PCA settlement.

Attached as Exhibit No. ___(JHS-24) are copies of each of the prefiled testimonies and the transcript of the oral testimony and cross-examination of this panel with respect to the PCA Mechanism (collectively, the "PCA Settlement Joint Testimony").

As described at page 3 of the prefiled testimony of William A. Gaines, the PCA Mechanism was "the product of collaboration and compromise."[1] Neither the PCA Mechanism nor the PCA Settlement Joint Testimony, which describes the

[1] *See* Exhibit No. ___(JHS-24) at page 26.

purpose and intent of the PCA Mechanism, defines or quantifies risk in terms of, or by reference to, the earnings retained by PSE in excess of its dividend. Indeed, neither the PCA Mechanism nor the PCA Settlement Joint Testimony refers to or is linked to retention.

Having participated in the PCA collaborative settlement negotiations, I disagree emphatically with the testimony of Messrs. Lazar, Schoenbeck and Mariam that the design of the current PCA Mechanism was related to PSE's retention. To my knowledge, PSE never stated nor agreed that retention was an appropriate measure of the extent of unrecovered power costs that PSE could absorb.

Q. What objectives did the Commission identify in approving the PCA Mechanism in Docket No. UE-011570?

A. The Commission stated the following objectives in approving the PCA Mechanism:

> A PCA mechanism should achieve an appropriate balance between risks to customers and risks to utility shareholders. The parties propose a mechanism that would result in a sharing of costs and benefits between PSE and its customers if power costs deviate significantly from those embedded in PSE's rates (*i.e.*, the "power cost baseline" established under the Power Cost Adjustment Issue Agreement).
>
> . . .
>
> In addition to providing PSE incentives to control power costs, the PCA also is designed to promote rate stability even in the face of fluctuating power costs.[2]

[2] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-011570 and UG-01157, Twelfth Supplemental Order: Rejecting Tariff Filing; Approving And Adopting Settlement Stipulation

Again, these objectives are not linked to, and do not refer to, retention.

Q. Was the PCA Methodology adopted in Docket No. UE-011570 required to continue unchanged in subsequent general rate proceedings?

A. No. As Mr. Lazar stated in his prefiled testimony describing and supporting the PCA settlement, the parties had a right to request changes in the PCA Mechanism at any time in the future:

> Because it is possible that not every potential situation has been considered, all of the parties have the right to request changes in the mechanism at any time in the future. I am optimistic that such changes will not be needed, but there is no "lock" on any of the methods for any period of time.[3]

Q. Do you agree with the Joint Testimony statement at page 22 that holding constant the return on rate base associated with Company-owned generation benefits the Company to the detriment of customers?

A. No. In the absence of a mechanism such as the PCA, fixed costs, such as the return on production plant and production O&M costs, are determined in a rate proceeding and included in the rate charged to customers. Recovery of these fixed costs will vary with load--such that a utility experiencing load growth, such as PSE, will experience revenue growth. Without a PCA mechanism, this increase in revenues helps cover the increased costs associated with the increased load. Under the PCA Mechanism, the Company gave up this revenue growth

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Subject To Modifications, Clarifications, And Conditions; Authorizing And Requiring Compliance Filing, at ¶¶ 22, 24 (June 20, 2002).

[3] Exhibit No. ___(JHS-24) at page 6.

between rate adjustments by holding the revenue recovery to the amount determined in the most recent general rate case or PCORC filing.

The Company also agreed to treat the revenues associated with regulatory assets as a variable cost and pass the benefit of the decreasing balance through to the customer. In the absence of the PCA Mechanism, the revenues associated with regulatory assets would not have decreased but would have grown in the same manner as the revenues associated with return on production plant and production O&M costs. Under the PCA Mechanism, the Company agreed to forego this revenue growth between rate adjustments and passes this benefit through to customers.

Q. Does the current PCA Mechanism provide for recovery of all of the Company's power costs?

A. No. For example, it appropriately does not provide for the recovery of the disallowances associated with Tenaska and March Point II. The existing PCA Mechanism also does not provide for recovery of power costs under the contracts listed in Exhibit E of the PCA Mechanism,[4] to the extent those power costs are higher than the costs of those contracts built into the power cost base rate. However, as recommended in my prefiled direct testimony, Exhibit E should be deleted and the costs associated with these contracts should be treated in the same manner as any other variable power cost.

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[4] A copy of Exhibit E is included within Exhibit No. ___(JHS-6).

Q. Does holding constant the return on rate base associated with Company-owned generation justify retention of Exhibit E?

A. No. The Joint Testimony at page 22 states that the "detriment" to customers that they perceive from holding return on rate base associated with Company owned generation constant somehow balances the perceived benefit to customers of retaining Exhibit E. However, as I discussed earlier in this testimony, the Company is already providing a benefit to the customers by foregoing revenue growth on production plant and regulatory assets.

The power cost contracts listed on Exhibit E are for Qualifying Facilities ("QFs") under PURPA, small hydro facilities and other contracts that are not related to Company-owned resources. As stated in my prefiled direct testimony, the contracts shown on Exhibit E have been approved by the Commission for inclusion in rates. This alone justifies removal of Exhibit E.

However, there is another reason to remove Exhibit E that is also addressed in my prefiled direct testimony. Exhibit E does not true-up costs symmetrically. When the actual contract cost is higher than the Exhibit E contract rate, the difference, multiplied by the actual quantity, is not used in the PCA true up calculation. When the actual contract rate is less than the Exhibit E contract rate, the actual cost is used in the true up and PSE does not receive a credit to offset the higher contract rate described above. This asymmetrical approach is inequitable.

The Company therefore requests that the Commission remove Exhibit E from the PCA Mechanism calculation. If the Commission wishes to continue the use of

Exhibit E, then it should be modified to use the actual amounts shown on this schedule in the PCA true up rather than the lower of the actual cost or the approved forecast.

B. Depreciation Tracker

Q. Have you reviewed the testimony of other parties as it relates to the Company's proposed depreciation tracker?

A. Yes.

Q. Would you please address the issues raised by the other parties.

A. Yes. One of the primary concerns raised by these parties is that adoption of the Company's proposed depreciation tracker would constitute single issue ratemaking. However, this Commission has frequently recognized tracking mechanisms as acceptable. For example, the Commission approved the Power Cost Only Rate Case as part of the PCA Mechanism, stating as follows:

> We expressly clarify that the Power Cost Only Rate Review provisions in the PCA settlement allow for single-issue rate making.

The prefiled direct testimony of Mr. James Russell in this case states as follows:

> The Commission's general policy is to approve trackers, deferrals, and the creation of regulatory assets only on a very limited basis for the following circumstances:
>
> - To address narrow, material, cost items that have no offsetting savings and are beyond the utility's control, such as certain energy costs;

- To spread certain major cost items over the proper generation of ratepayers, such as the deferral of the $89 million Chelan Payment (See Mr. Story's direct testimony beginning at page 78); and

- To create the proper incentives in narrow targeted areas, such as certain demand side management costs.[5]

The proposed depreciation tracker fits each of these circumstances.

Q. How does the depreciation tracker address narrow, material, cost items that have no offsetting savings and are beyond the utility's control?

A. The depreciation tracker addresses only the "recovery of" and not "recovery on" transmission and distribution system investments made since the end of the most current test year. This capital investment is being made to help maintain system reliability and help meet the customers' increasing demands for safe and reliable energy service, as discussed in detail in Ms. McLain's prefiled direct and rebuttal testimony,. The need for such expenditures can not be controlled by the Company. For example, local jurisdictions require relocations of utility facilities and work must be undertaken to meet mandatory safety regulations or orders. Moreover, as described in Ms. McLain's rebuttal testimony, these investments do not result in savings that offset their cost.

Q. Does the depreciation tracker spread major cost items over the proper generation of ratepayers?

A. Yes. As explained in my prefiled direct testimony, depreciation of plant begins when it is placed in service. Under the proposed depreciation tracker, the

[5] Exhibit No. ___(JMR-1T) at page 25.

customers that benefit from the investment and the service it provides pay the depreciation on, or the "recovery of," such investment.

Q. Does the depreciation tracker create proper incentives in narrow targeted areas?

A. Yes. In her prefiled rebuttal testimony, Exhibit No. ___(SML-5T), Ms. McLain discusses current events that underscore the need for capital investment in replacement and upgrade of transmission and distribution facilities. The timely commencement of the recovery of that investment would provide incentive to the Company to make such investments on behalf of its customers and facilitate the Company's ability to finance such investment.

A depreciation tracker is particularly important because (1) the revenue requirement for new plant is greater in the earlier years of its life, causing regulatory lag; and (2) replacement facilities are typically more expensive than the facilities being replaced due to inflation that occurred during the life of the replaced facility.[6] The depreciation tracker only covers the second item above.

Q. Is the Company's proposal "unusual and extreme ratemaking", as suggested by Mr. Ralph C. Smith at page 5 of his prefiled response testimony?

A. No. The Company is not asking that the Commission increase its revenues for the "recovery on" this new capital investment between regulatory proceedings.

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[6] Ms. McLain points out in her prefiled direct and rebuttal testimony that the costs of replacing capital facilities can not be measured by current overall inflation rates but has to be looked at in the context of the many years that the capital item has been in-service as well as in the context of the price inflation that is occurring with respect to the specific materials required for the delivery systems.

Instead the Company is requesting that it be able to earn "recovery of" the new investment. The Company will still be at risk to manage its earnings between regulatory proceedings to minimize the loss associated with not recovering the carrying costs of the new transmission and distribution capital investment. In addition, several states already have infrastructure trackers that include both "recovery on" and "recovery of" new investments in infrastructure.

Q. Mr. Smith argues in his prefiled response testimony, Exhibit No. ___(RCS-1T) at page 5 that PSE's proposed depreciation tracker should be rejected because it could remove or reduce incentives to prudently control the cost of plant additions. Do you agree?

A. No, Mr. Smith's argument should be rejected. As discussed above and as discussed in Ms. McLain's testimony, the depreciation that would be recovered by the proposed tracker results from the additional investment in transmission and distribution that is needed to help maintain and increase system reliability for PSE's customers. None of the other parties has suggested that the levels of delivery system investments projected by PSE are unreasonable or imprudent. As discussed earlier in this testimony, the depreciation tracker would facilitate investment in needed transmission and distribution plant. Failure to provide for timely recovery of depreciation maintains a disincentive to make this type of investment and is not in our customers' best interest.

Mr. Brosch, on page 16 of his prefiled response testimony, Exhibit No. ___(MLB-1CT), makes an argument that is similar to Mr. Smith's argument. Both arguments should be rejected for the same reasons.

Q. Have you reviewed the portion of Mr. Russell's prefiled testimony that discusses the Company's gas and electric attrition analyses and current earnings, pages 26 through 29?

A. Yes. Mr. Russell discounts the attrition analyses as being incomplete because they are a comparison and trending between two test years. He further states on pages 27-28 of his prefiled response testimony, Exhibit No. ___(JMR-1T), that attrition analyses are "very subjective" and "have been very rigorous, complex (and contentious) economic studies".

Q. Is Mr. Russell's characterization of the Company's attrition analyses correct?

A. As I discussed in my direct testimony, the attrition analyses done by Mr. Karzmar and myself are trended analyses. Mr. Russell does not mention that the Company also provided the results of its financial model run, which shows the financial results of gas and electric operations for 2007. The financial model is run under the direction of Mr. Donald Gaines, and the assumptions and results of the model were provided to all parties in Mr. Gaines' workpapers. The financial model run takes into consideration the complex interactions of the different economic considerations that Mr. Russell criticizes as missing from the attrition analysis. Thus, the Company did take economic factors into account--in the financial model rather than the attrition analyses. In our prefiled direct testimony, Mr. Karzmar and I discuss the trended analyses and financial model results and contrast some of the major differences between them.

Q. Mr. Smith testified that, instead of the depreciation tracker, the Commission could address post-test year plant additions through a known and measurable adjustment to recognize non-revenue producing, non-expense reducing transmission and distribution plant additions. Would the Company agree to such an alternative to the depreciation tracker?

A. Yes, if the Commission would prefer to use the known and measurable method to provide the Company more timely recovery of these investments, the Company would agree to such an alternative. However, the Commission should not limit such an adjustment to plant put in service during the limited time frame proposed by Mr. Smith of October 1 through December 31, 2005. Instead, the Commission should include all non-revenue producing transmission and distribution plant added to ratebase since the end of the test year that is known at this time. Ms. McLain's prefiled rebuttal testimony and supporting exhibits provide that information through June 2006.

Q. Have you calculated the impact on the revenue requirement of investment in non revenue producing transmission and distribution plant added to ratebase from the end of the test year through June 2006, as discussed by Ms. McLain in her testimony?

A. Yes. As reflected in Exhibit No. ___(JHS-25), the impact on Electric is to increase the revenue deficiency by $8.8 million. The impact on Gas is to increase the revenue deficiency by $3.5 million.

Q. How was the impact on revenue deficiency determined?

A. The methodology for calculating the revenue deficiency is laid out in Exhibit No. ___(JHS-25). As a brief overview for both electric and gas, the net additions of non-revenue producing projects to transmission and distribution plant were determined for the period from October 2005 through June 2006. Net additions consist of additions, retirements and transfers. The depreciation expense, accumulated depreciation and accumulated deferred federal income tax associated with these monthly additions were then calculated. The average of these nine monthly averages were then calculated to determine the impact on ratebase. The requested after tax rate of return of 7.57% was then applied to this additional ratebase amount to determine the operating income requirement. The operating income requirement was then grossed up by the respective conversion factors to determine the revenue requirement associated with ratebase. To this, the depreciation expense, adjusted for revenue sensitive items, was added in order to determine the overall revenue requirement impact, which in this case is also the impact on the revenue deficiency, associated with these known and measurable additions to plant. Exhibit No. ___(JHS-25) presents the detailed data used to calculate the components discussed above.

VIII. CONCLUSION

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.