EXHIBIT NO. ___(JHS-14T)
DOCKET NO. UE-072300/UG-072301
2007 PSE GENERAL RATE CASE
WITNESS: JOHN H. STORY

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-072300** **Docket No. UG-072301**

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

JULY 3, 2008

PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF JOHN H. STORY

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Are you the same John H. Story who provided prefiled direct testimony in this proceeding on December 3, 2007, on behalf of Puget Sound Energy, Inc. ("PSE" or "the Company")?

A. Yes. On December 3, 2007, I filed direct testimony, Exhibit No. ___(JHS-1CT), and seven exhibits supporting such direct testimony, Exhibit No. ___(JHS-2) through Exhibit No. ___(JHS-8). On April 14, 2008, I filed supplemental direct testimony, Exhibit No. ___(JHS-9T), and four exhibits supporting such direct testimony, Exhibit No. ___(JHS-10) through Exhibit No. ___(JHS-13C).

Q. Please summarize the purpose of your rebuttal testimony.

A. This rebuttal 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 to which the Company agrees and has incorporated in its updated electric revenue requirement determination. I will also discuss adjustments proposed by Commission Staff and other parties that the Company feels are inappropriate and explain why the Company disagrees.

Based on the proforma and restating adjustments proposed by the Company and presented in Exhibit No. ___(JHS-15), there is an electric revenue deficiency of $165,161,545. Firm Resale customers are allocated $102,391 of this deficiency and the resulting retail sales revenue deficiency of $165,059,154 represents an average 8.99% rate increase. This increase does not reflect an additional Production Tax Credit associated with the new turbines being constructed at the Hopkins Ridge Wind Project.

Based on the proforma and restated power costs for the test year, I present revised exhibits for the Company's Power Cost Adjustment ("PCA") 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, November 3, 2008.

Finally, I discuss concerns raised by some of the parties about PSE's PCA mechanism and its associated Power Cost Only Rate Case ("PCORC"). The Company agrees with Mr. Roland Martin that there are some changes to the PCORC process that would benefit all parties.

II. COMPARISON BETWEEN PSE'S REVENUE DEFICIENCY AND COMMISSION STAFF'S REVENUE DEFICIENCY

Q. Have you prepared a reconciliation between the revenue deficiency filed by the Company in its filing and the revenue deficiency 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	**$179,675,349**
Changes proposed by/agreed to by PSE in Rebuttal:	
Colstrip availability	(3,704,364)
Change Rate of Return to 8.51% per Mr. Gaines	(3,036,428)
Change Depreciation Lives on Encogen and Frederickson 1	(2,559,906)
Change Catastrophic Storm Life to four years	(2,485,614)
Normalize NERC Vegetation Cost	(1,778,423)
Update Property Tax Levy	(790,811)
Various Adjustments Under $500,000	(158,259)
PSE Rebuttal Filing Revenue Deficiency	**165,161,545**
Difference in Cost of Equity	(19,109,474)
Depreciation Study	(17,896,388)
Staff Adjustment to Working Capital	(10,454,607)
Staff proposal for Hydro Filtering	(9,812,709)
Baker Hydro Relicensing project costs	(4,259,280)
Incentive Pay	(2,362,305)

Merger Related Expenses	(721,008)
Difference in Cost of Debt	3,373,484
Wire Zone Vegetation	1,778,423
Colstrip forced outage	973,317
Property Tax – update levy rates	768,169
Production Adjustment	637,334
Various Adjustments Under $500,000	241,731
Commission Staff Supplemental Revenue Deficiency	**$108,318,232**

Q. Did any other parties have adjustments to the Company's revenue deficiency?

A. Yes. Some of the adjustments proposed by other parties have been included in the Company's rebuttal revenue deficiency, which I will discuss in the context of the relevant proforma or restating adjustment. Later in my testimony I will discuss the adjustments that the Company disagrees with or provide a reference to other Company witnesses that have testimony that discusses why a particular adjustment is inappropriate.

III. UNCONTESTED ELECTRIC ADJUSTMENTS BETWEEN PSE 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-15) summarizes the Company's restating and pro forma adjustments. This exhibit is presented in the same format as my Exhibit

No. ___(JHS-4) and Exhibit No. ___(JHS-11), and Mr. Weinman's Exhibit No. ___(WHW-2) and Exhibit No. ___(WHW-7).

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
15.01 Temperature Normalization	(7,470,315)	
15.02 Revenues and Expenses	49,427,844	
15.04 Federal Income Tax	(9,826,242)	
15.06 Hopkins Ridge Infill	540,198	10,325,850
15.07 Wild Horse Wind Plant	(2,191,792)	62,547,669
15.08 Goldendale	(1,033,352)	48,370,961
15.09 Sumas	(1,540,690)	24,744,721
15.10 Whitehorn	(1,481,961)	15,270,982
15.12 Pass-through Revenues & Expense	(974,801)	
15.13 Bad Debts	(527,902)	
15.16 Excise Tax & Filing Fee	454,544	
15.19 Interest on Customer Deposits	(350,242)	
15.20 SFAS 133	576,937	
15.21 Rate Case Expenses	131,455	
15.24 Pension Plan	453,665	
15.25 Wage Increase	(2,857,518)	
15.26 Investment Plan	(115,142)	

15.27 Employee Insurance	(985,713)	
15.30 Amortize Goldendale Fixed Cost Def.	(9,753,673)	6,763,253
15.32 Regulatory Assets and Liabilities	(8,718,601)	(69,560,204)
15.34 Skagit Facility	(809,652)	19,640,179

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

A. Yes. There are five adjustments that Mr. Weinman lists as uncontested that the Company has updated for changes in estimates to actual amounts. Although the adjustments are prepared in the same manner as the Company and Commission Staff proposed, the impact of the adjustment has changed. I discuss the differences between these Company adjustments and Commission Staff adjustments for the electric deficiency, and Mr. Karl Karzmar discusses the differences for the natural gas deficiency in his prefiled rebuttal testimony, Exhibit No. ___(KRK-11T).

Q. Please identify the adjustments on Mr. Weinman's uncontested adjustments list that are different in the Company's rebuttal exhibits.

A. The adjustments are 15.15, Property Taxes, 15.17 D&O Insurance, 15.18 Montana Electric Energy Tax, 15.22 Deferred Gain/Loss on Property Sales and 15.23 Property and Liability Insurance.

IV. CONTESTED ADJUSTMENTS

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

A. Yes. The impact on net operating income and rate base for each of the Company adjustments is shown on pages 15-A through 15-D of Exhibit No. ___ (JHS-15).

A. Power Cost Adjustment 15.03

Mr. David Mills' prefiled rebuttal testimony describes the differences between the Company's power cost adjustment and the power cost adjustment proposed by Mr. Buckley. Although the Company is proposing a change to the Colstrip forced outage rate that addresses some of Commission Staff's concerns, see Mr. Michael Jones prefiled rebuttal Exhibit No. ___(MJ-15T), the forced outage rate adjustment is not calculated in the same manner as proposed by Commission Staff. Both Mr. David Mills, Exhibit No. ___(DM-12T), and Dr. Jeffrey Dubin, Exhibit No. ___(JD-1T), discuss why the hydro filtering proposed by Mr. Buckley is inappropriate for adjusting power costs and should not be accepted by the Commission.

If the Commission determines that going to a four-year average of availability for the Colstrip units is not appropriate, the power cost adjustment the Company filed in its supplemental testimony would be the appropriate adjustment to use.

B. Federal Income Tax, Adjustment 15.04

This adjustment is not contested between the Company and Commission Staff. Mr. Matthew Marcelia, Director of Tax for PSE, will be taking over responsibility for this adjustment, which was prepared by his department for this rate proceeding. Mr. Marcelia has filed rebuttal testimony, Exhibit No. __ (MRM-1T), explaining numerous errors made by Public Counsel witness Mr. Michael Majoros in his calculation of federal income tax.

C. Tax Benefit of Proforma Interest, Adjustment 15.05

Mr. Danny Kermode, in his prefiled testimony, lists this adjustment as uncontested and it is not disputed between the Company and Commission Staff as to the 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 average interest costs proposed by the parties. Mr. William Weinman does have an error in his calculation in that the interest rate of 3.74% shown on his adjustment appears to be hard coded and does not equal the interest rate of 3.75% used in his rate of return calculation.

D. Hopkins Ridge Infill Project, Adjustment 15.06

The Company and Commission Staff agree on this adjustment. Mr. Majoros adjusts the depreciation rate to that proposed by Mr. Charles King for Hopkins

Ridge. Mr. C. Richard Clarke discusses why the depreciation rates developed by Mr. King are inappropriate.

E. <u>Wild Horse Wind Plant, Adjustment 15.07</u>

The Company and Commission Staff agree on this adjustment. Mr. Majoros adjusts the depreciation rate to that proposed by Mr. King for Wild Horse. Mr. Clarke discusses why the depreciation rates developed by Mr. King are inappropriate.

F. <u>Goldendale, Adjustment 15.08</u>

The Company and Commission Staff agree on this adjustment that annualizes the cost for Goldendale. The Company purchased Goldendale and put it in-service during the test year. This adjustment follows the same procedures used in prior dockets where a generating plant that was approved for recovery in a preceding docket was put in-service during what has become a test year for a new proceeding. In the preceding docket, the full value of the new plant was included in the revenue deficiency as a proforma adjustment.

Public Counsel witness Mr. Majoros' proposed disallowance of the adjustment to annualize the cost of Goldendale is inappropriate for several reasons. First, as discussed above, his adjustment is inconsistent with past Commission procedure. Further Mr. Majoros' proposed disallowance would require the Company to take a rate reduction associated with Goldendale as compared to what is currently included in rates. The full cost of this plant was included in Docket No. UE-

070565 and was approved by the Commission for recovery. Mr. Majoros also ignores the fact that the generation associated with this plant is included in power costs for the full rate year. He has created a mismatch between the costs and the related benefits of the power by only adjusting the cost side of the equation.

The Company asks the Commission to accept the calculation of this adjustment as proposed by the Company.

G. <u>Whitehorn, Adjustment 15.10</u>

The Company and Commission Staff agree on this proforma adjustment. Commission Staff also reviewed the purchase analysis and cost of this resource and is recommending the Commission approve the purchase as prudently incurred. In contrast, Public Counsel witness Mr. Majoros proposes to remove the cost of Whitehorn from the revenue deficiency.

Q. What reason does Mr. Majoros give for proposing that this resource not be included in the calculation of the Company's revenue deficiency?

A. Mr. Majoros has not provided any sound reasoning for removing the cost of the Whitehorn plant, which will go into service as a PSE-owned facility in February 2009, after the current lease expires. He has provided his interpretation of "known and measurable" which is contrary to past Commission decisions. Also, he references the Company's response to Public Counsel Data Request No. 318, which is unrelated to Whitehorn. This data request did not ask for a definition of "known and measurable" as implied by his testimony. *See* Exhibit No. ___ (JHS-18) for a copy of this response.

Q. Will Whitehorn go into service during the rate year?

A. Yes. In Mr. Roger Garratt's prefiled direct testimony, and again in his prefiled rebuttal testimony, he discusses (i) how the Company entered into an Asset Purchase Agreement on October 16, 2006 for Whitehorn; (ii) that FERC approved the Asset Purchase Agreement under section 203 on December 22, 2006; and (iii) that PSE is contractually committed to close the Whitehorn transaction in February 2009, which is the end of the current lease.

Q. Has the Commission previously approved the addition of a generating plant that had an in-service date during the rate year?

A. Yes. In the recent past Frederickson I was approved in a Company PCORC filing, Docket No. UE-031725 and Hopkins Ridge was approved in Docket No. UE-050870. The actual in-service dates were not known at the time of the Commission order so the costs were approved and there was a true up process in the PCA calculation to reflect the actual in-service date of the plant.

In addition, the Commission has approved numerous rate changes that reflect projected power costs for the rate year.

Q. Why do you calculate the rate year costs associated with new production plant instead of the test period?

A. When new production plant has not been in the test period it is necessary to calculate the recoverable costs that the Company will incur during the rate year. Historical test year production plant costs plus new production plant costs and power costs, which are also calculated at rate year levels, are adjusted by the production factor to bring the recoverable costs back to the test period. For power costs, this adjustment is made in the Power Cost Adjustment, Adjustment 15.03. For production plant and other production related costs, this adjustment is made in the Production Adjustment, Adjustment 15.35. As rates are set on the delivered load in the test period this adjustment decreases the costs associated with the production plant and power costs to test period levels. Assuming that everything else remains as originally projected, with the growth in load between the test period and the rate year, the Company will recover only the revenues approved to cover production costs during the rate year. This procedure for determining production and power costs has been in effect for many years.

H. Baker Hydro Relicensing, Adjustment 15.11

Commission Staff lists this adjustment as contested. Both the Company and Commission Staff agree to the prudency, amount and calculation of the adjustment; however, Commission Staff removes this adjustment to reflect its recommendation that this adjustment be removed if the Company has not received the final license from FERC prior to the issuance of an order in this Docket. The Company is in agreement with Commission Staff's proposal if the license is not granted prior to the issuance of an order in this docket.

I. Miscellaneous Operating Expense, Adjustment 15.14

The Company and Commission Staff agree on the majority of the adjustments to expense and on the rate base adjustment shown on this adjustment page. Both the Company’s supplemental filing and Commission Staff had shown the rate year $4,000,000 wire zone vegetation management fee as being a cost that should be included in determining rates. Mr. Ralph Smith of the Federal Executive Agencies ("FEA") proposes that this fee be normalized over three years due to the cost variance shown for this program. The Company believes this is a reasonable adjustment and has accepted Mr. Smith’s three-year normalization adjustment.

Mr. Roland Martin from Commission Staff has listed several items such as the cost of printing and distributing annual reports to shareholders, shareholders meetings and transfer agent fees totaling $689,215 that might be cost savings that the Company would experience if the merger is approved. These costs are similar to the New York Stock Exchange fees, $73,891, shown on my Adjustment 15.14, that are potential savings if the merger is approved and finalized. The Company does not contest these amounts if the merger is approved; however, these costs will be incurred by the Company if the merger is not approved. If the merger is not completed prior to the order for this proceeding these costs should be removed from both the Company's and the Commission Staff's adjustment as the outcome will not be known. PSE is in agreement with Commission Staff that the savings will be deferred upon completion of the merger with accrual of interest at the authorized net of tax rate of return.

Mr. Majoros, on behalf of Public Counsel, proposes that the amortization period of the interest associated with the residential exchange payment deferral be increased to seven years. Mr. Majoros points to another adjustment that amortizes a benefit that the Company received from the building owner of its general office facilities when the owner purchased back a buyout option from the Company as justification for this increase in residential exchange payment amortization. In proposing this adjustment Mr. Majoros ignores the fact that the customers that received the early payment of the residential exchange credit should be the ones to pay the cost of providing this benefit to them early. To fit in with regulatory timing, the Company has used a future recovery period, which will allocate some of these costs to new customers. Mr. Majoros moves even more of the cost recovery to future customers. This is in contrast to the benefit of the referenced lease buyout option, referenced by Mr. Majoros, that is going to the customers that will be paying the future lease payments. Moreover, the lease buyout amortization was not proposed by the Company but was proposed by Commission Staff after the Company filed an accounting petition to address this issue. The Commission should accept the amortization for residential exchange payment deferral proposed by the Company and by Commission Staff in its prefiled response testimony.

J. Property Taxes 15.15

Commission Staff and the Company's supplemental filing for this adjustment are the same. Prior to filing rebuttal the Company was successful in having the levy rates adjusted downward from what had previously being assessed by the Department of Revenue. The Company's rebuttal adjustment reflects this reduction in levy rates and projects the rate year tax liability on these lower rates.

K. Director and Officers Insurance, Adjustment 15.17

Ms. Joanna Huang, in her prefiled testimony, lists this adjustment as uncontested and states there is no dispute as to the methodology used in the calculation. Mr. Majoros of Public Counsel proposes to remove the impacts of increased premiums brought on by pending litigation that was not related to regulated operations. The Company has accepted Mr. Majoros' adjustment.

L. Montana Electric Energy Tax, Adjustment 15.18

Commission Staff and the Company agree on the methodology used to make this restating adjustment. The difference in the amount of the adjustment is based on how much Colstrip will generate during the rate year. Because we have used different availability factors for Colstrip – as discussed by Mr. Mills in his prefiled rebuttal testimony – the amount of generation from Colstrip is different.

M. Deferred Gains and Losses on Property Sales, Adjustment 15.22

This is an uncontested adjustment between the Company's supplemental filing and Commission Staff's filing. The Company has updated the deferred gains and losses on property sales since the supplemental filing to reflect their balances as of May 31, 2008.

N. Property and Liability Insurance, Adjustment 15.23

This is an uncontested adjustment between the Company’s supplemental filing and Commission Staff’s filing. In rebuttal, the Company has updated the premium amounts to actual known premiums versus the estimated premiums used in the Company’s supplemental filing.

O. Incentive Pay, Adjustment 15.28

Ms. Huang, in her prefiled testimony, proposes to remove 50% of the incentive payments she has determined are tied directly to earnings per share ("EPS") from 2005 to 2007 and is proposing recovery of only the incentive payments she has determined are tied to customer service oriented benefits. Mr. Majoros proposes that the Commission disallow all of these costs.

Ms. Huang testifies that in several orders the Commission clearly states that incentive plans not tied to goals benefitting ratepayers will be disallowed. She claims that in Docket Nos. UG-040640 and UE-040641, in which the Commission allowed the Company incentive payments, the Commission was unaware of the earnings per share impact on the Company's incentive payment. *See* Exhibit No. ___ (JH-1T) at page 7. Mr. Majoros also argues that the Company uses earnings per share to fund the incentive program and points to several Commission decisions, dated 1999 and earlier, where the Commission had disallowed incentive payments when they are based on earnings per share.

The Commission addressed these arguments in the Company's 2004 general rate case. In the Final Order No. 6 of Docket Nos. UG-040640 and UE-040641 at page 55, paragraph 144, the Commission stated:

> We find that while a portion of PSE's incentive plan payments turns on the Company reaching certain earnings goals, there is a second threshold for such payments that is based on service quality, safety, and reliability considerations. These are the criteria we have looked for in authorizing, or not, the recovery of incentive payment costs. Since they are present here, we find it is not appropriate to disallow a portion of the costs as Staff advocates.

Mr. Thomas Hunt's prefiled rebuttal testimony describes the incentive program and why it should be a recoverable cost of employee compensation. Mr. Hunt also discusses the funding for the program and why the funding meets the Commission criteria for allowing recovery of these costs. The Company has calculated the incentive pay adjustment consistent with the procedure established in Docket Nos. UG-040640 and UE-040641.

P. <u>Montana Corporate License Tax, Adjustment 15.29</u>

The Company and Commission Staff are in agreement on methodology for this restating adjustment. The difference between the two adjustments is the pre-tax income from the Tax Benefit of Proforma Interest Adjustment. As the Company and Commission Staff have different rate base amounts after proforma and restating adjustments the pre-tax income is different. Public Counsel's adjustments to federal tax rates and other proforma and restating adjustments do not correctly calculate for this adjustment.

Q. <u>Storm Damage, Adjustment 15.31</u>

Mr. Kermode from Commission Staff recommends a four-year amortization of the catastrophic storms (other than the December 13, 2006 Hanukkah Eve Storm), rather than the three-year amortization proposed by the Company in its supplemental filing. The Company accepts Staff's recommendation and updates the amortization period from three years to four years. In addition, the Company also updated the 2006 storm deferral balance for an accounting adjustment that transferred a portion of the 2006 storm costs to capital. These costs were associated with the replacement of a unit of property during that storm and should have been capitalized at the time of the storm.

Q. Did other parties propose adjustments to the storm damage expense?

A. Yes. Mr. Smith, on behalf of the FEA proposes to change the amortization of the Hanukkah Eve Storm to ten years while both the Company and Commission Staff have proposed a six-year amortization of this storm cost. On page 8 of Mr. Smith's prefiled response testimony he provides a table that shows several "observations" and he associates an amortization period to each of these observations. Although Mr. Smith apparently pulled these dates from a Company data response, the years presented in Mr. Smith's table are not relevant to determining an amortization period for ratemaking. As stated in the article referenced in footnote 4 of Mr. Gregory Zeller's prefiled direct testimony there have been at least six "100-year" storms since 1986 in the greater Seattle area. As shown by the years associated with the other "observations", we have been fortunate that this area has not had storms of this magnitude in the recent past. This is no guarantee that it will not happen again or that it will not happen sooner rather than later. Although no one would want another storm like the Hanukkah Eve Storm in the near future, the likelihood of it happening again has nothing to do with Mr. Smith's "observations".

Mr. Smith also refers to the average remaining life of the Company's transmission and distribution plant to justify a longer amortization period. This information is also irrelevant as these costs are not capital expenditures. These costs are a regulatory asset consisting of items which would normally be expensed as incurred but for the procedure the Commission has approved for cost deferral and rate recovery.

Mr. Smith goes on to argue that ten years of cost recovery mitigates the impact on customers more than six years of cost recovery. This is true as any longer amortization period will make current rates lower than a shorter amortization period. However, this is also irrelevant as it ignores the higher costs associated with the longer recovery period and a longer amortization allocates more of the costs to new customers that were not here during the storm.

Ms. Barbara Alexander, on behalf of Public Counsel and the Energy Project, proposes a 5% disallowance associated with the Hanukkah Eve Storm. Ms. Alexander admits, however, that this amount is not based on any review of reasonableness. *See* Exhibit No. ___ (BRA-1TC) at page 8, lines 11-12. Mr. Zeller in his prefiled rebuttal testimony discusses why the operational reasons presented by Ms. Alexander as possible justification for this unsupported adjustment should not be accepted by the Commission.

Mr. Majoros, on behalf of Public Counsel, proposes that the Commission use what he characterizes as "excess amounts collected from ratepayers for future costs of removal" to offset all of the test year storm damage expenses. "Cost of removal" is a part of the Company's depreciation rates and included in accumulated depreciation for purposes of rate making. Mr. Jan Umbaugh and Mr. William Stout both discuss why Mr. Majoros's characterization of this cost of removal is flawed and how his analysis is based on a misrepresentation and misinterpretation of what Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS 143"), and FERC Order No. 631 require for accounting for retirement obligations. Mr. Michael Stranik also discusses how Mr. Majoros' use of amounts booked to accumulated depreciation violates FERC accounting guidance.

Mr. Majoros proposes another "monetary adjustment" to storm damage on page

14, lines 9 through 19 of his testimony where he discusses a $7 million limit. Mr. Majoros clearly does not understand what is meant by a "$7 million dollar limit previously set by the Commission". This $7 million is the IEEE catastrophic storm related cost limit that the Commission set in the Company's 2004 general rate case. It is used to determine when the Company can defer catastrophic storm costs. Before the Company can defer costs associated with catastrophic storms it must have incurred $7 million dollars of IEEE-defined storm costs. Only costs associated with a storm that meet the IEEE measurement standard are allowed to be defined as catastrophic storm costs and are eligible to be deferred. This $7 million is not a limit on storm costs charged to expense as there are other storm related costs that do not meet the IEEE measurement standard. Mr. Majoros uses his misinterpretation of the IEEE catastrophic storm limit amount to erroneously limit the determination of normalized storm expense in the storm damage adjustment. The Company and Commission Staff have calculated the normalized storm expense correctly, and Mr. Majoros's flawed calculation should be rejected by the Commission.

As stated in my prefiled testimony, the Company is requesting that the Commission use the calculation of normalized storm expense to define the level of IEEE related storm costs that must be incurred, and expensed, prior to deferring catastrophic storm costs. In this proceeding such a change is actually an increase of $1 million from the previous $7 million dollar limit.

Mr. Marcelia addresses Mr. Majoros' proposal to flow through the tax benefit of storm damage costs and why this short term view of tax relief would be detrimental to customers in the long run. As an example of the impact the flow through of storm related taxes would have on customers, I have provided Exhibit No. ___ (JHS-19), which is a calculation of the revenue requirement impacts over the six year period of amortization. In year one, there would be a $15,945,435 decrease in revenue requirement followed by a $55,942,241 increase in revenue requirement in year two under Public Counsel's proposal. It is surprising that Public Counsel would advocate this approach and the rate volatility it would cause.

Q. Is Public Counsel recommending any recovery for storm damage as depicted in Exhibit No. ___ (JHS-19)?

A. No. The amounts shown for recovery are based on the Company's presentation of the storm damage adjustment. Mr. Majoros has proposed that the Commission use the part of the accumulated depreciation reserve associated with cost of removal to offset the costs associated with storm damage. As I discussed above, Mr. Umbaugh, Mr. Stout and Mr. Stranik discuss the appropriate implementation of SFAS 143, Accounting for Asset Retirement Costs, and how cost of removal is correctly recorded for PSE. There are no "over collections" in accumulated depreciation to apply to storm damage.

R. Depreciation Study, Adjustment 15.33

Both Commission Staff and Public Counsel's witness Mr. King propose adjustments to the depreciation study that the Company submitted with its initial filing. *See* Mr. Clarke's prefiled direct testimony at Exhibit No.___ (CRC-1T) and accompanying exhibits at Exhibit No.___ (CRC-2) and Exhibit No. (CRC-3).

Commission Staff agrees with Mr. Clarke’s remaining life, life span concepts and net salvage estimates. Commission Staff does take exception to Mr. Clarke’s plant lives, 29 and 30 years respectively, used for Encogen and Frederickson 1 in “Other Production Plant” and the Colstrip plant life, 40-45 years, used in “Steam Production”. Mr. King also takes exception to the plant lives determined by Mr. Clarke for these assets.

Commission Staff points out that assets in Other Production Plant in the depreciation study use 35 year lives. Mr. King points to a study conducted by his firm which determines that combustion turbines should have lives in excess of 46 years, however, he proposes to change the combustion turbine lives to 45 years. As Mr. Clarke points out in his rebuttal testimony, the depreciation rates he determined for these plants are appropriately documented by the actual plant operations and this supports the lives he used for Encogen and Frederickson 1 plus all other production plant. However, the Company finds that Commission Staff's adjustment for these two plants is not unreasonable and has asked Mr. Clarke to change the lives for Encogen and Frederickson 1 to 35 years. The Company’s rebuttal depreciation adjustment reflects this adjustment for all plant related to Encogen and Frederickson 1. This adjustment varies from Commission Staff’s supplemental filing as there was an account that was not associated with

Encogen or Fredrickson 1 that was adjusted to the 35-year life in Commission Staff's supplemental filing. The current and proposed rates for the Fredrickson Project (not to be confused with the Fredrickson 1 Project) in FERC Account E345 were incorrectly changed from 0.04% and 6.75%, respectively, to 3.33% and 3.34%, respectively. This has resulted in a difference between the Company's and Commission Staff's deficiencies of approximately $200,000.

The Company believes the 40-45-year lives used for Colstrip in Mr. Clarke's depreciation study are appropriate. Mr. Clarke and Mr. Jones both address this issue in their rebuttal testimony.

Mr. Clarke, Mr. Umbaugh and Mr. Stout also address the rest of the depreciation adjustments proposed by Mr. King, on behalf of Public Counsel, which deal with net salvage values and Mr. King's misapplication of financial accounting concepts presented in SFAS 143, Accounting for Asset Retirement Costs, FIN 47, Accounting for Conditional Asset Retirement Obligations – an interpretation of FASB Statement No. 143 and FERC Order 631. Mr. Stranik addresses the inappropriate use of cost of removal to offset storm damage costs as proposed by Mr. Majoros.

Mr. Weinman also makes a change from the manner in which the depreciation true up has been calculated in the past. He removes the adjustment to rate base, stating that it is effective outside the test period and that it is not appropriate to adjust rate base with a proforma adjustment. He points to the Company's wage adjustment as proof the Company agrees with this concept. The Company does not agree with this concept or this analogy. The wage adjustment does not adjust rate base as it would not be practical to forecast when wages charged to future construction work in progress will be closed to in-service. Both the Sumas and Whitehorn adjustments in this proceeding are proforma adjustments and do have rate base adjustments calculated.

Mr. Weinman also proposes that the depreciation rates accepted by the Commission in this docket become effective January 1, 2008. In support of this effective date Mr. Weinman points to two recent Commission orders that had PacifiCorp and Avista change their depreciation rates effective January 1, 2008. The Company disagrees that this retroactive adjustment is appropriate or that it is justified by either of the orders cited by Mr. Weinman. One of the orders was in Docket UE-071795 and addressed an Accounting Petition filed by PacifiCorp on August 31, 2007, which presented a new depreciation study that lowered depreciation rates $1.2 million. PacifiCorp specifically requested that the Commission approve a January 1, 2008 implementation date for the new study as the Company kept its depreciation on an annual basis. The Commission approved this accounting petition on April 10, 2008. The second order was in Docket No. UE-070804, which was Avista's general rate case filing. The Settlement Agreement in this docket was approved by the Commission, and, pursuant to the Settlement Agreement, Avista implemented new customer rates effective January 1, 2008, and also implemented its new depreciation rates at the same time.

PSE has continued to use the depreciation rates approved by the Commission in its 2001 general rate case for financial and regulatory reporting purposes. The Company has no basis to adjust these depreciation rates until after it receives the Commission order approving the new depreciation rates. Commission Staff has offered no reasonable justification as to why publicly reported depreciation expense should be adjusted by a future Commission order. The Company requests that the Commission approve the implementation of any depreciation rates effective with the month the Commission order for this proceeding is effective for rates.

Mr. Stranik addresses how the Company implemented SFAS 143 and FIN 47 for financial reporting purposes and how the impacts of these financial accounting procedures are removed for regulatory purposes.

Q. **<u>Production Adjustment, Adjustment 15.35</u>**

Changes to the production adjustment reflect the changes made to the adjustments discussed earlier that have production related costs and are not included on the power cost adjustment.

Q. **Are you the Company witness that will discuss the Commission Staff adjustments shown for Billing Discounts and a Working Capital Disallowance?**

A. No. Mr. Karzmar discusses these adjustments in his prefiled rebuttal testimony,

Exhibit No. ___ (KRK-11T). The Company does not believe these adjustments are appropriate and requests the Commission reject them for both electric and natural gas operations.

Q. Is Mr. Weinman's adjustment to remove the costs associated with the Crystal Mountain Diesel Spill appropriate?

A. In his supplemental testimony, Mr. Weinman agrees that the Company had properly adjusted for these costs and has eliminated this adjustment from his determination of revenue deficiency.

Q. Do you have any further discussion associated with proforma and restating adjustments?

A. Yes. Several parties have proposed adjustments to the Company's operating results some of which I have discussed above. I will discuss why the remaining adjustments are not appropriate below.

R. Adjustments Proposed By Other Parties

Q. Please continue with your discussion of other parties proposed adjustments to the test year.

A. I will list each adjustment by type of adjustment and provide the Company's response below.

1. <u>Remove Expenses Related to Shareholders</u>

Mr. Majoros on pages 42 and 43 of his testimony lists the costs of being a public company for Puget Energy, and its only subsidiary PSE, and recommends these be disallowed. His justification for this adjustment is that it is his opinion shareholders should incur these types of costs. In addition, he would exclude one-half of outside directors' costs. Mr. Majoros does not provide any basis for this adjustment other than his opinion. Realizing his opinion is probably not enough to disallow costs that have been recoverable in operating expense for decades, and are costs that support the Company in its ability to attract and utilize capital for the benefit of customers, he adds that with the merger he expects that these costs will no longer be necessary at all. This statement is only partially true as there will still be directors and costs of “financial, operating and other data required by regulatory statutes.” The issue of cost savings associated with merger savings has already been addressed by the Company and Commission Staff as explained earlier in my testimony. Mr. Majoros’s adjustment should be rejected.

2. <u>Remove Expenses Relating to Athletic Events</u>

This is a relatively minor item that Mr. Majoros would remove from operating expense “as attendance at athletic events is not essential to the provision of safe, reliable electric service, and does not benefit customers.” The Company does not agree with this assessment. This event does help to provide employees from all levels of the Company access to the various officers and departmental directors of the Company. It gives employees the ability to discuss questions they may have about the Company with the executives and others at the event in a non-business setting and provides contacts that can be helpful in getting answers for customers in the future. Also, Mr. Majoros seems to discount this activity because it gets its participants from an employee pool. Because this is a popular event, the employees are drawn from an "employee pool" with some attention to making sure there are representatives from multiple areas. It should be noted that the large majority of the costs of this facility are charged below the line to shareholders because technically they are considered to be "lobbying", although they also provide benefits to customers. The Company feels these costs are appropriate operating expenses; however, if the Commission orders the Company to charge these costs below the line in the future it will do so.

3. <u>Executive Compensation</u>

Mr. Majoros makes numerous observations about executive compensation and proposes to disallow compensation costs for several officers. Mr. Eric Markell, Ms. Kimberly Harris and Mr. Thomas Hunt in their prefiled rebuttal testimony explain why these observations are incorrect and discuss why officer compensation is appropriate as filed by the Company.

Mr. Majoros also questions the validity of the data received from the Company in response to Public Counsel's Data Request No. 674 ("PC DR 674") in relation to the data used in support of the Wage Increase Adjustments. *See* Exhibit No. __

(JHS-11) at page 11.25 and Exhibit No. ___ (KRK-9) at page 9.18. These two sets of data he claims are inconsistent are related, but are not determined on the same basis. One set of data shows the amounts paid to the officers during the test year, which Mr. Majoros requested in Public Counsel Data Request No. 674,[1] and the other set of data reflects officer compensation included in the financial statements during the test year. One difference between these two amounts is that compensation paid to employees is based on pay periods that are not month end dates. The financial statements include accruals for the difference between the pay period dates and month end. If an employee's salary changes over the year then the actual salary plus the accrued amounts for the year would not equal compensation paid during the year. This happens because the amount paid to the employee over twelve periods would reflect the lower salary from another financial period.

Another reason for the difference between the amount paid to an employee versus what is in an accrual basis financial period is that paid time off ("PTO") is booked as an average corporate overhead to the accounts that an employee charges when at work. If an employee takes more or less days off than what is represented by the overhead rate applied to his or her salary, then the financial statements would be different from the actual salary paid for that specific employee. In total the salary charges and PTO liability accrued for compensation are accurate.

[1] "Please indicate . . . each element of compensation actually paid . . . ."

4. Domestic Production Activities Deduction

This issue is moot as the benefit of this deduction, when available, is included in the PTC calculation tracker per the Commission's Final Order in Docket No. UE-060266. Mr. Marcelia describes the errors in Mr. Kevin Higgins' calculation of this deduction and explains how the calculation is actually done to provide an understanding as to why the Company is not eligible for this deduction at this time.

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

A. Yes.

V. REVENUE DEFICIENCY

Q. Would you please explain Exhibit No. ___(JHS-16)?

A. Exhibit No. ___(JHS-16) presents the calculation of the revenue deficiency based on the proforma and restating adjustments proposed by the Company and that were discussed above. As shown on page 1 of this Exhibit No. ___(JHS-16), based on $3,298,173,579 invested in rate base and $178,053,576 of net operating income, the Company would have an electric retail revenue deficiency of $165,059,154.

A. Cost of Capital

This schedule, shown on page 2 of Exhibit No. ___(JHS-16), reflects the

Company's proposed capital structure for this proceeding and the associated costs for each capital category. The capital structure and costs are presented in the prefiled rebuttal testimony of Mr. Donald Gaines. *See* Exhibit No. ___(DEG-8CT). The rate of return is 8.51%.

B. <u>Conversion Factor</u>

The conversion factor, shown on page 3 of Exhibit No. ___(JHS-16), 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 0.6213371% and is uncontested between the Company and Commission Staff. Public Counsel witness Mr. Majoros uses his calculated effective tax rate to determine a conversion factor. Mr. Marcelia explains why Mr. Majoros's effective tax rate is erroneous and should not be accepted by the Commission.

C. <u>PCA Exhibits</u>

Q. Please describe Exhibit No. ___(JHS-17C).

A. Exhibit No. ___(JHS-17C) 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 $63.544 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 rate base 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 that is required to implement the Commission's final order.

VI. POWER COST ADJUSTMENT MECHANISM

Q. Were you involved in the development of the 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 that presented the PCA mechanism to the Commission for approval as part of a settlement in Docket No. UE-011570. This joint panel consisted of the following:

(i) Mr. W. James 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.

Q. Was the PCORC part of the PCA mechanism discussed in the settlement?

A. Yes. The PCORC was defined in the Settlement Terms for the Power Cost Adjustment Mechanism. *See* Exhibit No. ___ (JHS-8) at page 3, paragraph C.5, and page 5, starting at paragraph 8.

Q. Is the Company in agreement with the proposed changes to the PCORC as presented by Commission Staff?

A. Yes, with one modification that is addressed in Ms. Harris's prefiled rebuttal testimony. I also discuss one additional change that would assist in simplifying the PCORC process.

In addition to the Commission Staff's proposals the Company would suggest a change to the sixth bullet item in paragraph C.8 of the settlement agreement. This change is to correct the wording to state;

- A calculation of proforma production cost schedules that are consistent with the Company's most recent general rate case, including power supply and other adjustments impacting then current production costs.

The original purpose of this bullet item was to simplify the PCORC in that new methods and proposals for calculating power costs were left for a general rate case setting. With the original wording saying “this docket” instead of “most recent general rate case” the intent was not clear.

Q. Ms. Lee Smith for Public Counsel states that the Company’s PCA mechanism is different than other states' power cost adjuster in that the Company now has three methods for changing rates associated with power costs instead of two. Do you agree with her assessment?

A. No. Ms. Smith incorrectly assumes that the annual PCA filing is a mechanism to change rates. This annual filing is a report that provides all interested parties the chance to review the power costs as incurred during the most recent PCA period for prudency. *See* paragraph B.4, bullet item 3 in the Settlement Terms for the Power Cost Adjustment Mechanism.

She is correct that there is a surcharge or credit that can be requested if the deferred balance under the PCA calculation gets to be greater or less than $30 million. In most power cost adjustments this over or under collected amount is adjusted at the time the mechanism is trued up, for example, in a PCORC or general rate case filing. As this adjustment was not going to be included in a general rate case or PCORC, the surcharge mechanism was added so that if the balance were to get out of line there was a method to correct for it. Over time, if power costs are set appropriately, these credits and charges should offset each other, and this has proven to be true over the last five-and-a-half years of the PCA. This surcharge also recognized that the Company could ask for emergency rate relief if for some reason power costs were far outside “normal” costs. There has been no surcharge requested since the PCA mechanism has been in place.

Q. On page 11 of Ms. Smith’s testimony she provides a summary of how the PCA mechanism operates. Do you agree with her summary?

A. No. Ms. Smith begins her explanation by stating that the PCA "compares actual power costs to PCA allowable costs.” This is incorrect. The PCA only compares PCA-defined actual power costs with PCA-approved allowable costs. This is an important distinction that Ms. Smith tries to minimize later in her testimony. Paragraph 7 of the settlement terms for the PCA mechanism states as follows:

> New resources with a term of less than or equal to two years will be included in the allowable PCA costs. The prudence of these resources will be determined in the Commission’s review of the annual PCA report. New resources with a term greater than two years may be included in the PCA allowable cost at the lesser of the actual cost or the average embedded cost in the PCA (including transmission into PSE’s Puget Sound system) as a bridge mechanism, until the then future costs of these new resources can be reviewed in a Power Cost Only Rate review.

This paragraph is further defined by Exhibit G to the PCA mechanism. As can be seen on that exhibit only the variable costs of a new plant are included in the calculation. There is no fixed cost recovery allowed and anything in excess of the current baseline rate is disallowed for purchase power agreements or the variable costs associated with fixed assets. These excess power costs are not even considered in the PCA calculation for determining what is to be shared between customers and the Company. The Company absorbs all these excess power costs.

Q. Why were these provisions included in the PCA mechanism?

A. Prior to the PCA, other parties expressed concern in the Company's ECAC filings in the 1980s and PRAM filings in the 1990s that the Company was able to bring in new resources for power cost recovery without a prudency review. Paragraph 7 and Exhibit G were designed to make the Company come in for review of new resources if the costs exceeded the baseline rate. If the Company chose not to adjust the base line costs the costs were ignored for PCA tracking purposes and the Company had to absorb the additional costs. The only way that the costs of resources can be actually tracked is for the baseline rate to be reset with the appropriate portfolio mix of old and new resources.

Q. In her discussion as to why regulatory lag is not a significant factor Ms. Smith uses an example of a wind farm to show that the Company would have energy produced at essentially no variable cost therefore it could benefit the Company. Is that an appropriate example?

A. No. Ms. Smith ignores that wind generation is intermittent or non-firm, requiring other resources to be held in reserve to firm and shape the wind generation to approximate a firm source of generation. Even if she were right, not all new resources are going to be wind owned by the Company. A power purchase agreement to buy the output from a wind project typically will have all the costs of the project built into the contract. Other firm base load plants such as gas plants are not low variable cost resources and would have a financial impact on the Company.

Q. Ms. Smith on page 14 states that "without the intervention of PCORCs, as I will demonstrate, there would have been larger Company positive and negative deferrals, but fewer rate changes". Do you agree with her analysis?

A. No. Ms. Harris discusses how, without a PCORC, the timing of purchases may be different dependent on the financial capability of the Company. Moving timelines around based on regulatory filings does not capture the change in the operating environment that would have happened without a PCORC.

The hypothetical rate case schedule devised by Ms. Smith is also flawed. For example she shows on Exhibit No. __ (LS-3) at page 4, the months of October 2004 through February 2005 and March 2006 through December 2006 with no amounts calculated for differences between actual allowed power costs, explained earlier, minus the costs built into rates. This may have been done for analytical convenience but is a highly unlikely scenario.

In addition, under her analysis the Company's October 2005 PCORC was filed in June 2005 as a general rate case. She makes the unwarranted assumption that this general rate case would have settled and new rates would have gone into effect in February 2006, rather than May 2006, which would have been the date under the eleven month statutory limit. Even if the above general rate case schedule assumptions were warranted, which they are not, the Company would have had to file a new general rate case the same month (February 2006) in order for the next general rate case order to have been entered in January 2007, as it was.

Q. Is Ms. Smith's table on page 24 of her testimony accurate?

A. No. The original amount requested in Docket No. UE-050870 was $68.7 million, not $101.9 million, and the percent from new resource would be 56% not 38%. Ms. Smith appears to have added the PCORC update that was agreed to by all parties which was filed in the second quarter of 2006 to her requested amount. This update was to change the PCA reporting period to a December ended period from a June ended period. This was an agreed upon filing that followed a settlement to the original filing. It used a predetermined formula approach for the update and was not related to adding resources.

Mr. Donald Schoenbeck also has an error at page 5 of his prefiled response testimony, Exhibit No. ___(DWS-1T), regarding the same filing. The $5.7 million he uses for Hopkins Ridge is after crediting what would have been market purchases to the plant costs in the absence of Hopkins Ridge and the $55.6 million he uses is already net of PTC. His numbers should have been the same as I discussed above.

Q. Is the percentage of a new resource to revenue deficiency relevant?

A. No. With a change in rate year, portfolio mix, gas prices and contracts, the total revenue deficiency can end up being high or low depending how all these pieces fit together. During this period of increasing prices, total power costs ended up being higher than the previous proceedings estimates.

Ms. Smith's and Mr. Schoenbeck's contention that the PCORC was only designed to add new resources is also wrong. Paragraph 8 of the Settlement Terms for the Power Cost Mechanism states:

> there would be a periodic proceeding specific to power costs that would true up the Power Cost Rate to *all power costs* identified in the Power Cost Rate. The Company can also initiate a power cost only proceeding to add new resources to the Power Cost Rate.

(emphasis in original). This paragraph has not been altered by the Commission or the Company's 10-K statements as Mr. Schoenbeck would like everyone to believe.

Q. Do you agree with Ms. Smith that new owned generating units will result in increased revenues from increased retail or wholesale sales that will offset lag?

A. No. Not only are new plant costs higher than average historical plant costs, but the revenue requirement for the first year of a new plant is generally higher than the market power that is being replaced. As has been shown in recent Company filings, the first year cost of a new Company-owned resource is higher than the equivalent market purchases and it is over the life of the project that the benefit of the new resource is better than the alternatives.

It is also highly speculative to say that a new asset will produce increased revenues from wholesale electricity sales. The Company does not acquire new resources in order to sell electricity on the wholesale market, but acquires new resources to serve customer load. Without a change in rates, recovery will not occur through customer growth alone.

Q. Would any changes have to be made to the PCA if the PCORC is eliminated?

A. Yes. There is a fixed cost component in the baseline rate used in the PCA mechanism that remains constant until reset in a future PCORC or GRC. This part of the PCA mechanism allows the Company to recover only the allowed costs for these items and offsets any growth in revenues due to sales growth against the variable power costs. Without a PCORC, this fixed cost component of the PCA true-up would need to be eliminated

I mentioned this fixed cost component in my pre-filed testimony as being a benefit in the PCORC. In a new PCORC or GRC process, if the change in recovery of these items is less than what was last set for recovery, due to accumulated depreciation increasing or a change in unit cost, it will help offset increases in variable costs. In the PCA process it is a benefit as any growth in revenues due to sales growth above what was allowed in the most recent PCORC or GRC is offset against the actual variable power costs in the PCA true up process. This calculation helps lower the power costs set aside for sharing.

Ms. Smith, on page 33 of her testimony, talks about how allowing for this growth in revenues may be a benefit compared to a mechanism that does not allow for growth but it is not a benefit compared to a GRC. Previously, on page 31 of her testimony she discusses how in the absence of a PCORC the Company can recover costs through a general rate case if revenue increases resulting from increased sales were not sufficient to provide adequate revenues. However, without eliminating the fixed cost component of the PCA true-up the Company has no growth in revenues associated with the fixed cost component of the baseline rate.

To accomplish Public Counsel's objective to rely on general rate cases and accounting deferrals, this component of the PCA true-up would have to be eliminated. The Company is not recommending that the PCA or PCORC be eliminated but is providing this as an example of how the PCA and PCORC in the PCA mechanism were designed to work together.

Q. Would you please summarize your discussion on the PCORC?

A. The PCA and the PCORC are dependent on each other. Without the proper setting of the baseline rate used in the PCA calculation not all power costs are even considered in the true up and sharing bands of the PCA mechanism. The Company is in agreement with Commission Staff on suggested changes that should make the PCORC less burdensome. In addition, the Company asks to clarify bullet point six in paragraph C.8 of the PCA mechanism agreement.

VII. CONCLUSION

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.