Exhibit No. JT-1CT
Dockets UE-090704/UG-090705
Witness: Alan Pl. Buckley
Donald W. Schoenbeck
REDACTED VERSION

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	DOCKET UE-090704 and DOCKET UG-090705 *(consolidated)*

JOINT TESTIMONY

OF

ALAN P. BUCKLEY
AND
DONALD W. SCHOENBECK

ON BEHALF OF

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Power Supply Issues

November 17, 2009

CONFIDENTIAL PER PROTECTIVE ORDER – REDACTED VERSION

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EXHIBIT LIST

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Alan P. Buckley. My business address is the Richard Hemstad Building, 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia, Washington 98504. I am employed by the Washington Utilities and Transportation Commission ("Commission") as a Regulatory Analyst. My qualifications are contained within Exhibit No. APB-1.

A. My name is Donald W. Schoenbeck. My business address is 900 Washington Street, Suite 780, Vancouver, Washington 98660. My qualifications are contained within the individual testimony I am sponsoring on behalf of the Industrial Customers of Northwest Utilities ("ICNU"), Exhibit No. DWS-2.

II. SCOPE AND ORGANIZATION OF TESTIMONY

Q. What is the purpose of your testimony?

A. The principal purpose of this testimony is to address Puget Sound Energy Inc.'s ("PSE" or the "Company") rate year power cost projections, as contained in the Company's May 8, 2009 General Rate Case Direct Testimony and the September 28, 2009 Supplemental Direct Testimony. A summary of ICNU/Staff recommended adjustments are reflected in Exhibit No. JT-2.

Q. How is the remainder of your testimony organized?

A. The testimony is divided into five sections. Section I contains the introduction. Section II describes the scope and organization of this testimony. Section III summarizes the ICNU and Staff recommended adjustments to the Company's rate year power cost projection.. Section IV presents the detailed discussion of those recommended adjustments. Finally, Section V addresses the future treatment of the Tenaska Amortization, a significant annual expense that ends year-end 2011.

III. SUMMARY OF ICNU/STAFF RECOMMENDATIONS

Q. Please summarize your recommended adjustments.

A. The ICNU/Staff power cost projection adjustments are divided into two categories – "AURORA" related costs and "Out-of-AURORA" related costs. The adjustments related to AURORA costs are carried out first, as they may have an effect on the determination of the Out-of-AURORA adjustments.

In addition, ICNU and Staff are recommending specific treatment for costs associated with the mark-to-market gas hedge expense and the Tenaska Amortization expense that are presently embedded in the determination of rate year power cost projections. If these significant extraordinary and short-term costs are not removed from the determination of base electric rates, those amounts will continue to be reflected in base rates, even though PSE no longer incurs the costs, until such time a subsequent general rate case is processed.

Exhibit No. JT-2 presents a summary list of the individual ICNU and Staff recommended adjustments to rate year power cost projections at the expense level. Exhibit No. JT-3C shows the overall effects of ICNU and Staff's adjustments to rate year power cost projections in a comparative format to that presented by the Company. The actual revenue requirement effect of the total adjustments is presented in Staff Exhibit No. KHB-2, Pages, 2.10, 2.14 and 2.15.

The rate year power cost projection, as filed in the Company's September 28, 2009 Supplemental Direct Testimony, is used as the basis for ICNU and Staff's recommended adjustments. Overall, the ICNU/Staff recommended adjustments result in a $38.6 million reduction in the total rate year power cost projection. The recommended treatment of the Tenaska Amortization will result in a future approximate $40.2 million reduction in rates (at the revenue requirement level) beginning on January 1, 2011; however, the Tenaska Amortization has no immediate effect on revenue requirements in this proceeding.

Specifically, ICNU and Staff are recommending the following actions regarding PSE's proposed power cost projection:

1. For purposes of this proceeding, the Company's proposed Rate Year Power Cost Projection, as contained in its September 28, 2009, Supplemental Direct Testimony, should be adjusted by the amounts indicated in Exhibit No. JT-3C.
2. The Commission should order the Company to reduce base electric rates by the revenue requirement amount equal to the market-to-market gas hedge expense level approved by the Commission and to implement a tariff rider to recover this expense on a kWh basis from customers. This tariff rider should have a sunset date of March 31, 2011.
3. The Commission should order the Company to reduce base electric rates by the revenue requirement amount equal to the annual Tenaska Amortization expense revenue requirement level and to implement a tariff rider to recover this expense on a kWh basis from customers. This tariff rider should have a sunset date of December 31, 2011.

IV. RECOMMENDED ADJUSTMENT DISCUSSION

A. AURORA Adjustments

1. Upper/Lower Baker Generation

Q. Please describe the Upper/Lower Baker Project Generation adjustment.

A. The ICNU/Staff recommended adjustment corrects for what appears to be an inadvertent error by the Company in which an incorrect time period was used to determine the Lower and Upper Baker test period generation. Correcting the error increases generation of the Lower and Upper Baker projects, thus lowering the overall rate year power cost projection. Based on a single average water year AURORA run, this inadvertent error reduces the power supply cost by $1.8 million. Combined with the other AURORA related adjustments proposed by ICNU and Staff, the reduction in the rate year power cost projection is $1.37 million, as indicated in Exhibit No. JT-2. This error was acknowledged by PSE in response to ICNU Data Request No. 02.15, which is included as Exhibit No. JT-4.

2. Regional Load Forecast

Q. Please summarize your AURORA Load Forecast adjustment.

A. The Company's September 28, 2009 Supplemental Filing includes a significant reduction in forecasted rate year electric loads. Rate year loads were reduced by

932,382 MWhs or about 106 average MWs, as compared to PSE's initial filing. This represents an approximate 3.9 percent reduction in loads, as compared to the initial filing. The new load forecast also represents an approximate 1.2 percent decline from even test year weather adjusted loads, a significant factor in determining costs for the Company.

Rate year forecast loads, adjusted for losses, are used to determine rate year net power supply costs. As a result of the load reduction, rate year net power supply costs decreased significantly. However, this reduction was in large part negated when determining overall revenue requirements, due to the straight application of the production factor adjustment. The Company failed to consider any other regional load reductions based on any kind of economic trend data equivalent to what was used for its own internal purposes. This ICNU/Staff adjustment corrects for this oversight.

Q. Why is consideration of PNW regional loads important in determining rate year net power supply costs?

A. In addition to using PSE's own load for dispatching Company-owned resources, the AURORA power supply model uses regional loads throughout the western United States and Canada for determining market electricity prices for purposes of making balancing sales and purchases. These prices are in large part determined from the variable costs of marginal resources used to meet regional loads for this entire area. It follows then, that as regional loads are reduced, less efficient marginal plants do not have to operate as much, thus reducing regional market prices as well.

Depending on the resource position of the Company, this may result in reduced net power supply costs as determined for the AURORA power supply model.

Q. Did PSE reduce the regional loads in the AURORA data base in its Supplemental Filing?

A. No. In regard to the updated load forecast, the Company stated it only: "...updated the load forecast to reflect economic and demographic trends in its service territory." (PSE Response to ICNU Data Request No. 02.29) No adjustments were made to the 30 individual areas encompassing all or parts of eleven states, two Canadian provinces, and part of Baja, Mexico that are included within the WECC region modeled in the AURORA data base used in this proceeding. The aggregated regional load was not even reduced by the 106 average MWs of PSE load reduction, as compared to the original direct case filing. PSE stated that: "The PNW loads were not reduced by the same amount (as PSE's load reduction) because it is PSE's opinion that this minor change would probably not make a material difference to PSE's projected power costs." (PSE Response to ICNU Data Request No. 02.28) No studies confirming this claim have been provided.

Q. Have other regional utilities reduced their load forecasts due to regional economic conditions?

A. Yes. The settlement agreements in both the recent Avista and PacifiCorp general rate cases incorporated reductions in retail loads compared to what was filed or originally prepared. Further, as noted in the Northwest Power Pool Area Assessment of Reliability and Adequacy 2009-2010 Winter Operating Conditions (dated September 9, 2009), the weather adjusted 2009 summer peak was 4,500 MW below the forecasted value:

> The economic recession that began in 2007 has had an impact on the Power Pool power usage and future forecasts. The 2009 summer peak forecast for the Power Pool area, as one single entity, was 54,500 MW. The actual was 50,000 MW adjusted for temperature. The recession that has taken place has impacted the Power Pool area between 5 to 10% reduced demand. Historically, the Power Pool area lags the economic recovery by approximately one year.

Q. How did you determine your AURORA Load Forecast adjustment?

A. To derive what we believe is a conservation adjustment, the PNW loads and the loads of Southern California and Pacific Gas & Electric, which together represent a significant portion of WECC loads, were input into the AURORA model assuming no load growth for 2009, 2010 and 2011. This conservative approach still results in a rate year power cost projection reduction of approximately $ 1.1 million based on a single average water year AURORA run. When determined in conjunction with the other AURORA related adjustments, the decrease in the rate year power cost projection is $0.83 million as indicated in Exhibit No. JT-2.

3. Hydro Filtering

Q. What is the purpose of your Water Filtering Adjustment?

A. The water filtering adjustment better aligns the methodology for determining base power supply costs with a regulatory environment that includes an annual PCA, as compared to the traditional normalized power supply cost methodology. The water filtering adjustment addresses the power supply cost uncertainty associated with extreme, or outlier, water years and the calculation of projected rate year power costs, appropriately leaving the review and recovery of costs associated with those years, if indeed they do occur, to the annual PCA review when all costs are known.

Q. What are the uncertainties associated with extreme or outlier years and why is it appropriate to make this adjustment?

A. Historically, the Company has based its adjustment on power cost models runs for a number of water years and then calculated a "normalized" level of net power supply costs. The effects on normalized power supply costs of the extreme water years, both wet and dry, have been particularly troublesome due to uncertainties in market prices for both power and fuel during extreme hydro years. In addition, the number of water years to use for a power supply study and their timing has been a contentious issue in many past rate proceedings, as parties attempted to eliminate or capture certain extreme water years for purposes of determining normalized power supply expense.

However, with a working PCA, it is possible to eliminate this controversy by narrowing the range of water years used to determine base power supply costs to those years representing what is more normally expected to occur, and dealing with the recovery associated with extreme water years only if they actually do occur. In this way, the base level power supply costs are not biased one way or the other through the inclusion of more extreme anticipated, but not as likely to occur, water conditions. It is important to remember that this adjustment is based on assumptions regarding the probability of water conditions, not normalized power supply costs, i.e. the filtering is carried out on water years, not the resulting annual power supply costs.

Q. How did PSE determine normalized power supply costs for hydro conditions?

A. Consistent with several past rate cases, PSE used the average of the 50-year Mid-C stream flow history from 1928 through 1977 to determine power costs for the rate year. The theory is to set rates using a range of actual power supply expense levels assumed to be experienced over time, and, thus, actual under-recovery of costs in some years is balanced by over-recovery in others. This methodology is acceptable, absent the PCA. However, net power supply cost normalization needs to be aligned with the presence of the PCA.

Q. You stated that both "review and recovery" of the extreme, or outlier, water year costs belong in the PCA. Please explain.

A. This is perhaps the most important feature of our adjustment to set base power costs using a narrower range, or more typical, number of water years. It is probably not surprising that the more extreme years typically result in the more "interesting" years costs-wise, particularly on the dry or drought side of the spectrum. By not including in base rates the effects of those extreme years on power supply costs, all parties, as well as the Commission, may evaluate the actual costs associated with any extreme water years should they occur in the annual PCA filings, without concern as to whether those costs may have previously been recovered in base power costs over time. This removes what we believe is a valid concern regarding the potential for double recovery of costs by the Company over time.

Q. Has the Commission favored a water filtering adjustment for utilities with a PCA mechanism?

A. Yes. The Commission has already agreed that water filtering is appropriate in the context of a PCA. The commission stated:

> If the Company and its customers will share the costs and benefits of unusual power cost extremes, there is no need to include those extreme circumstances in the calculation of normalized power costs, particularly if they are controversial. . . . We agree with Staff and PacifiCorp that water filtering is appropriate in the context of a PCAM, but not appropriate if there is no PCAM in place.

WUTC v. PacifiCorp, Dockets UE-061546, et al., Order 08 at ¶¶ 88-89 (June 21, 2007). Ultimately, a power cost mechanism was not adopted for PacifiCorp and a water filtering adjustment was not implemented. However, the water filtering adjustment has been a feature of recent general rate case settlement agreements in Avista proceedings. Application of a water filtering adjustment was appropriate, because Avista has a power cost adjustment mechanism, called the Energy Recovery Mechanism, or ERM, in place.

Q. How have you determined of your recommended water filtering adjustment?

A. The 50 years of water year data converted to generation energy on an annual basis as used by PSE in its AURORA model is used as the basis for filtering. It is important to recognize that the adjustment uses water year data, not the resulting annual net power supply costs as the basis for filtering. We have assumed normally distributed water year data, which also carries over into the resource by resource generation data actually used in the filtering calculation.

Total annual generation (representing the associated normally distributed water flow equivalent) for each of the Mid-Columbia hydro projects used in the AURORA model and for each of the water years has been used as the basis for filtering water years. A one standard deviation "filter" band on each side of the normally distributed Mid-Columbia project energy data (or water flow equivalent) is compared to the fifty water years of generation history. Those years in which total annual generation (again the "proxy" for water year conditions) was below or above the band are identified. This process identified nine years to exclude for being above the range and eleven years to exclude for being below the range. Finally, to calculate the Water Filtering Adjustment, the AURORA model is rerun using only the identified water years. The Company's modeled AURORA costs were then compared to filtered results to derive the adjustment.

Q. What was the basis for choosing a one standard deviation band for "filtering" the 50 year average water year generation data?

A. The choice of a one standard deviation filter was not based on a scientific study of any kind. It is a reasonable approach that results in the more extreme, or outlier water years, being removed without computational controversy. Applying a plus or minus one standard deviation band to the mean values is a simple and straightforward application to the normally distributed energy (water flow equivalent) data. It clearly eliminates the outlier water years when extreme water conditions exist, both favorable and unfavorable. It is an easy to understand departure from using the full 50-year water record and the traditional normalized methodologies for determining baseline net power supply costs under a PCA environment.

Q. If extreme, or outlier, water years and their associated power supply costs are removed from the rate-setting process, does the Company recover, or ratepayers receive the benefits of, the costs the Company incurs in such years?

A. Yes. The water filtering adjustment only removes the more "uncertain" net power supply costs from the normalization procedure. In the event extraordinary costs, or benefits, occur as a result of extreme water conditions, customers will pay a portion of these costs and receive a portion of the benefits, when and if they actually occur under the PCA mechanism.

Q. Earlier you stated that the water filtering adjustment provides benefits to ratepayers by more appropriately realigning risk sharing. Please elaborate?

A. The water filtering adjustment, while not eliminating the potential for increased costs, does take at least one "risk" factor out of the base power supply cost determination (and thus base electric rates) and puts it into the PCA where it belongs. Thus, the effect on power supply costs of extreme years can be more appropriately reviewed and analyzed as those events may occur and after actual costs and/or mitigating actions are known.

Q. What is the effect on Projected Rate Year Power Cost of ICNU and Staff's Water Filtering Adjustment?

A. As shown on Exhibit No. JT-2, the Water Filter Adjustment reduces the rate year power cost projection by approximately $5.7 million, as compared to PSE's 50 water year AURORA run.

B. Out of AURORA Adjustments

1. Mid-Columbia Projects Budget

Q. Please describe the Mid-Columbia Project Budget adjustment.

A. As a result of continued discovery, the "Out-of-AURORA" amounts assumed for purposes of rate year power cost projections associated with Chelan PUD's Rocky Reach and Rock Island projects and Grant PUD's Priest Rapids and Wanapum projects have been updated by PSE in this proceeding. An initial update was incorporated into the Company's September supplemental power cost projections. However, the budgets associated with the projects identified above have been updated further and are reflected in ICNU and Staff's recommended adjustment.

Q. What are the results of updating the Mid-Columbia Project's budgets on the Company's rate year power costs projection in this proceeding?

A. The Chelan PUD update for the Rocky Reach and Rock Island projects results in a $1,367,937 reduction to the rate year power costs projection. The decrease in the rate year power costs projection associated with Grant PUD's Priest Rapids and Wanapum projects is $761,362. These adjustments are identified and discussed in the non-confidential narrative responses to ICNU Data Request Nos. 03.11 and 03.14, included as Exhibit No. JT-5. Together these adjustments decrease the rate year power cost projection by approximately $2.1 million at the expense level, as indicated in Exhibit No. JT-2.

2. Westcoast Pipeline Capacity

Q. Please describe the issues associated with Westcoast Pipeline Capacity.

A. Westcoast is the Canadian interstate pipeline that interconnects with Northwest Pipeline at the US/Canadian border near Sumas. A few years ago, PSE acquired a small amount of Westcoast capacity as part of its acquisition of the Fredrickson Project. However, in PSE's initial and supplemental presentations in this proceeding, PSE is proposing to include in rates a substantial amount of additional Canadian interstate capacity. The Company's original filing included $5.8 million in Westcoast fixed pipeline charges; and, the supplemental filing includes approximately $8.7 million. According to PSE, the additional upstream firm pipeline capacity on Westcoast Pipeline was acquired: "in order to provide additional supply security and pricing diversity." (Exhibit No. RCR-4CT, line 3). The pricing diversity is direct access to "Station 2," a marketing hub on Westcoast that is comparable in market activity to Sumas. However, PSE has not indicated that it has had difficulty acquiring needed gas supplies at Sumas, a liquid gas market hub. The

Company offers the possibility of a decrease in the underlying firmness or liquidity of the Sumas hub, thus necessitating new Westcoast Pipeline holdings, but it is purely speculative at this point. This leads to the conclusion that the significant annual fixed costs associated with the Westcoast Pipeline capacity is only appropriate if it can be offset by annual savings in gas commodity costs from acquiring the supply diversity.

Q. Does the Company's filing reflect this commodity benefit?

A. To some extent, yes. PSE's initial and supplemental direct testimony only identified a minimal "basis gain" benefit of less than $200,000 associated with the acquisition of Westcoat Pipeline capacity "Basis gain" is a term used to identify benefits of acquiring gas supplies at diverse locations to serve customer needs. In response to an inadvertent error identified during the discovery process and brought to the attention of the Company, PSE has provided a data request response updating the rate year power cost projection implementing the "basis gain" correction identified by ICNU. It appropriately identifies additional supply benefit associated with the acquisition of the Westcoast Pipeline capacity. However, we believe additional benefits are required to justify the significant annual acquisition expense.

Q. Please first describe the specific error in the Company's Westcoast Capacity supply benefit calculation.

A. The identified error is a simple spreadsheet error in the worksheet calculating what is being called the "basis gain" associated with the Westcoast Pipeline capacity. The

Company's workpaper spreadsheet calculated basis gain for only one day a month instead of the full month's worth of days. As indicated in PSE's response to ICNU Data Request No. 02.24, included as Exhibit No. JT-6C, the Company confirmed the error, notified the parties, and calculated its effect on the rate year power cost projection, as well as the proposed PSE revenue requirement. Correcting the worksheet results in a reduction to the rate year power cost projection of $5.7 million, as indicated in Exhibit No. JT-6C and shown in Exhibit No. JT-2.

Q. You stated earlier this correction is not sufficient alone to justify the acquisition of the Westcoast Pipeline capacity. What additional adjustment are you recommending?

A. In the Company's Energy Management Committee presentation regarding the Westcoast Pipeline capacity, the ability to achieve supply diversity between Sumas and Station 2 is identified as the main factor supporting the acquisition. The corresponding "basis gain" related to the Westcoast Pipeline acquisition is estimated by the Company using the gas deliveries to several of PSE's large gas-fired generation resources, namely Fredonia 1, Goldendale, and Mint Farm. Forecasted gas price diversity is applied to the AURORA model's normalized volumes burned, and a savings, or "basis gain" determined by resource. ICNU and Staff believe there is a logic error in the Company's calculations which understates the estimated basis gain.

Q. Please describe the logic error in the Company's basis gain calculation.

A. There are no readily available forward gas prices for Station 2. Consequently, PSE used a <u>single</u> basis trade quote between the Alberta Energy Company or "AECO" trading hub and Station 2 hub in order to determine the test period forward prices at Station 2. That is, the Company derived forward prices for Station 2 based upon the forward price projections at AECO. Under the Company's calculation—based on the extraordinarily limited information of just a single broker quote—there are four months of the year when the forward prices at Sumas are lower than the forward prices at Station 2, as shown by the following table:

PSE Gas Price Comparison
($/MMBTU)

Month	Station 2	Sumas	Basis
April	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]
June	[redacted]	[redacted]	[redacted]
July	[redacted]	[redacted]	[redacted]
August	[redacted]	[redacted]	[redacted]
September	[redacted]	[redacted]	[redacted]
October	[redacted]	[redacted]	[redacted]
November	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]
January	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]
March	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]

After taking into account the Westcoast fuel in kind charge (2%), there are five months (May is the fifth month) when PSE is showing no commodity benefit from acquiring this substantial amount of Westcoast capacity. Accordingly, there are no estimated basis gains during these five months of the rate year.

However, historical data shows that in <u>every</u> trading day for the last two years, there has been a favorable price differential between Station 2 and Sumas. This makes sense as the cost for transporting gas from Station 2 to Sumas is about 47 cents/MMBTU for the test period. So, faced with the alternatives of buying gas at Station 2 and transporting it to Sumas versus simply buying the gas at Sumas, an entity needs a savings of at least 47 cents/MMBTU at Station 2 as compared to Sumas.

Q. How do you propose to correct PSE's basis gain calculation?

A. We recommend an historical basis gain differential be used to derive the Station 2 prices from the Sumas forward prices. We have calculated monthly basis adjustments between Station 2 and Sumas using historical trading data, as reported by Platts Gas Daily for 2008. We have chosen this year, as it represents more normal economic activity versus the current down turn that exists today. The following table presents the recommended ICNU/Staff basis adjustments that should be applied to the Sumas forward prices to derive the Station 2 prices.

Station 2/Sumas
Basis Adjustment
($/MMBTU)

April	-$0.564
May	-$0.352
June	-$0.219

July	-$0.301
August	-$0.289
September	-$0.378
October	-$0.401
November	-$0.422
December	-$1.336
January	-$0.869
February	-$0.575
March	-$0.441
Average:	-$0.512

Q. What is the effect of the additional ICNU/Staff adjustment to Westcoast Pipeline capacity benefits?

A. The adjustment corrects the Company's logic error and enhances the benefits that ratepayers should expect from the significant expense of the Company's Westcoast Pipeline capacity acquisition. It results in an additional $4.0 million in estimated annual benefits. Combined with the earlier identified correction, Out-of-AURORA rate year basis gain benefits should be increased by $9.7 million, resulting in an equal reduction in the rate year power cost projection, at the expense level, as indicated in Exhibit No. JT-2.

3. Mark-to-Market for Gas Hedges

Q. Please describe the issues associated with the mark-to-market adjustment for gas hedges.

A. There has been a gas mark-to-market adjustment in the last several general rate cases and power cost only rate proceedings. This post-AURORA adjustment has been done to incorporate PSE's actual short-term forward gas purchases (primarily financial but also physical) for the rate period since the AURORA run simply uses current forward prices. The following table shows these adjustment values for several of the most recent PSE proceedings.

PSE MTMs Amounts

Proceeding	Amount ($000)
2004 GRC	-$24
2005 PCORC	-$1,004
2005 PCORC Update	$509
2006 GRC	$4,296
2007 PCORC	$1,909
2007 GRC	-$5,166

As shown by the above table, these mark-to-market adjustments have been relatively modest.

However, in this filing, PSE's short-term mark to market adjustment is over $45 million. The adjustment is substantial since PSE has extended the forward time period over which it will buy gas and there is more base load gas-fired generation with the acquisition of Goldendale and Mint Farm. These two factors in and of themselves may make sense and may be reasonable. However, the level of the proposed adjustment in this proceeding is unreasonable because of another factor: PSE has procured too much gas for the test period.

Q. How has that occurred?

A. PSE uses different models and manages the electric portfolio differently on a day-to-day operational basis than is or can be reflected in AURORA. As just one example, we know PSE is very active in the wholesale market making hundreds of millions of dollars of wholesale sales each year through bilateral transactions. However, AURORA cannot capture this activity since it solves for the most efficient system (really West Coast) dispatch at just a single point in time. As a result of mismatches such as this, PSE is seeking a substantial sum for gas in excess of need as reflected in the AURORA simulation. The following table compares PSE's gas financial purchases with the base load need AURORA is forecasting for the test period. It shows a substantial—and inappropriate-- amount of hedged transaction versus need for the rate period.

PSE Gas Purchases v AURORA Need
(DTh/Day)

Month	Gas Need	Financial Hedges	Percent Hedged
Apr-10	[redacted]	[redacted]	[redacted]
May-10			
Jun-10			
Jul-10			
Aug-10			
Sep-10			
Oct-10			
Nov-10			
Dec-10			
Jan-11			
Feb-11			
Mar-11			
Rate Year	[redacted]	[redacted]	[redacted]

The next table presents a portion of the mark-to-market adjustment showing the results for all the Sumas hedges. As indicated by the weighted average values for the rate year, although the Sumas forward price is only [redacted]/MMBTU, PSE's revenue requirement in this proceeding adds an additional [redacted] million for above market costs:

PSE's MTM for Sumas Hedges

Month	Sumas Hedges	Sumas Forwards	Difference	MTM ($1000)
Apr-10	[redacted]	[redacted]	[redacted]	[redacted]
May-10				
Jun-10				
Jul-10				
Aug-10				
Sep-10				
Oct-10				
Nov-10				
Dec-10				
Jan-11				
Feb-11				
Mar-11				
Rate Year	[redacted]	[redacted]	[redacted]	[redacted]

Put another way, while PSE's AURORA result reflects a weighted gas price of about [redacted]/MMBTU, after taking into account the $45 million mark-to-market adjustment, the actual gas price reflected in PSE's revenue requirement filing is about [redacted]/MMBTU.

Q. How do you propose to correct for this mismatch?

A. We believe there is a simple and straight forward solution for incorporating PSE's forward gas procurement activity into the AURORA results to achieve an equitable normalized power supply cost for the rate period. The volume of forward gas purchases for each month should be capped at 80 percent of the AURORA-projected base load need for each month of the forecast period. The price to apply to this volume would be derived in the same manner PSE has done the calculation to date. The monthly forward purchase cost would be the actual weighted average price for all procured volumes. Using the base load gas need from our AURORA results, we recommend PSE's gas mark-to-market adjustment be reduced by $18.6 million. Based on PSE's AURORA simulation which has a higher gas need, this recommendation reduces PSE's mark-to-market adjustment by $11.8 million, as indicated in Exhibit No. JT-2.

Q. Are ICNU and Staff making any additional recommendations regarding the recovery of these gas mark-to-market related costs?

A. Yes. The unusual nature of these costs warrants a different treatment for their recovery. Whether the Commission adopts the gas mark-to-market levels of the Company or of ICNU and Staff in this proceeding, the amount is significant. ICNU and Staff remain concerned that the market-to-market levels being reviewed in this proceeding do not reflect in any way long-term or normal annual amounts. The higher than historical amount of the power supply expense item is due to the rapidly declining gas costs experienced recently by the Company and the continued implementation of PSE's gas hedging strategy into the rate year. As with the large annual amortization expense associated with the Tenaska Amortization discussed below, ICNU and Staff recommend that these extraordinary, short-lived, and non-reoccurring costs do not get embedded in customers' base electric rates for periods past the rate year at issue in this proceeding. In order to address this concern, ICNU and Staff recommend that the market-to-market costs adopted by the Commission be removed from the determination of customer base rates, and a separate temporary tariff rider be established to recover these costs during the rate period. The rider would allow recovery of any approved mark-to-market costs on a kWh basis and would sunset, or end, by April 1, 2011. Future mark-to-market benefits, or costs if any, would be an issue for future rate filings.

The actual specific tariff effects of this recommendation, as well as the similar recommendation for Tenaska Amortization costs discussed below, have not been included in any ICNU or Staff rate design testimony; however, we believe that the recommendation could be readily implemented.

4. Jackson Prairie Storage Capacity

Q. Please describe the issues associated with Jackson Prairie Storage Capacity.

A. This issue is similar to the Westcoast Pipeline capacity issue, because the Company is attempting to include costs associated with an acquisition in the rate year power cost projection, without including any corresponding benefits.

The Company claims that Jackson Prairie storage capacity is purchased to ensure the reliable provision of gas supply to customers and power generation facilities, and that gas storage also provides a measure of price management. CITE. However, it appears that PSE has not included quantifiable benefits in this proceeding related to the [redacted] cost of acquiring the Jackson Prairie storage capacity. Ratepayers should expect to receive benefits that at least partially mitigate the inclusion of the expense in the determination of the rate year power cost projection. When the proposed transaction ("Cabot Asset management Agreement") was presented to the Company's own Energy Management Committee on March 19, 2009, the presentation showed a cost of [redacted] per year with an associated value of [redacted] per year. (The EMC presentation is attached to this testimony as Exhibit No. JT-7C.) The value included a component related to the benefit associated with storage. No such benefit is reflected in the Company's filing in this proceeding. ICNU and Staff recommend a storage benefit be included from the difference in market prices between the low and high gas cost months, times the associated storage volume of the agreement. Based on PSE's Sumas forward prices, this calculation yields a benefit of [redacted] attributable to this arrangement.

Q. What is the total combined effect on the rate year power cost projection of the AURORA-related and the Out-of-AURORA adjustments?

A. As shown in Exhibit No. JT-3C, the AURORA model related adjustments decrease the rate year power cost projection by $7.87 million, while the Out-of-AURORA adjustments decrease the rate year power cost projection by $30.7 million. Together, ICNU and Staff recommend reducing the power supply costs by $38.6 million at the expense level.

C. Tenaska Amortization

Q. Please describe the issues associated with the Tenaska Regulatory Asset.

A. The rate year net power cost projection includes an annual $38.3 million expense associated with the buy down of the Tenaska fuel prices as determined in Docket UE-971619. This annual amortization is scheduled to end at the end of 2011. This amortization has been a significant component of the overall level of PSE's power supply costs over its life. ICNU and Staff want to bring to the Commission's attention that this significant burden will be embedded in existing rates unless the Company makes a timely filing that reflects the removal of these costs from rates, effective the beginning of 2012. There is no guarantee that the Company will make such a filing to ensure that these costs get removed from rates by that time.

Q. Given that possibility, what is your recommendation in this proceeding regarding the Tenaska Regulatory Asset?

A. ICNU and Staff recommend that base rates determined in this proceeding be reduced by the revenue requirement reflecting the Tenaska Amortization. A tariff rider corresponding to the removed amount should be established with a class specific kWh rate sufficient to recover those costs for the duration of the amortization period, but with a sunset, or ending date, of December 31, 2011. This recommendation represents a reasonable approach for the recovery of these costs, yet insures that these significant costs (approximately $40 million revenue requirement) are removed from customers' rates in a timely manner and with the least amount of administrative burden for the Commission and parties. It is the magnitude of these short-lived costs that support this somewhat unusual, but ratepayer-friendly approach.

Q. Does this complete your testimony?

A. Yes.

Exhibit No. JH-1T
Dockets UE-090134/UG-090135
Witness: Joanna Huang

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**DOCKET UE-090704** **DOCKET UG-090705**

TESTIMONY

OF

JOANNA HUANG

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Revenue Requirement Adjustments:
Wage Increases, Investment Plan, and Employee Insurance

November 17, 2009

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LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Joanna Huang. My business address is the Richard Hemstad Building, 1300 S. Evergreen Park Dr. SW, Olympia, WA 98504-7250. My e-mail address is jhuang@utc.wa.gov.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission ("Commission") as a Regulatory Analyst.

Q. What is your educational and professional background?

A. I received my B.B.A. degree majoring in Accounting from National Chung-Hsing University, Taiwan, in 1987 and a Master of Accounting degree from Washington State University in 1991. Prior to my employment at the Commission, I was employed by the Washington State Department of Revenue as an Excise Tax Examiner. I performed desk audits on Business & Occupation tax returns.

I began my employment with the Commission in 1996. My work generally includes financial, accounting and other analyses for general rate case proceedings and other tariff filings by the electric and natural gas utilities regulated by the Commission. I have attended the National Association of Regulated Utility Commissioners Annual Utility School in 1996 and 2001. In addition, I have attended numerous training seminars and conferences regarding utility regulations and operations.

Q. Have you testified previously before the Commission?

A. Yes. I testified in a Puget Sound Energy, Inc ("PSE" or "the Company") general rate case, Docket UE-072300 and UG-072301, a PacifiCorp general rate case, Docket UE-032065, and an Avista general rate case, Dockets UE-991606 and UG-991607. I have also participated in Staff's investigation in the following general rate cases: Dockets UE-070804 and UG-070805, UE-090704 and UG-090705 (Avista); Dockets UE-050482 and UG-050483 (Avista); Docket UE-011595 (Avista); Docket UG-060256 (Cascade); Docket UG-080546 (Northwest Natural), and UG-031885 (Northwest Natural).

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. My testimony presents Staff's review of eight adjustments proposed by the Company for its electricity ("E") and natural gas ("G") results of operations.

Q. Which adjustments have you reviewed that are uncontested by Staff?

A. The following two adjustments are uncontested by Staff:

- Adjustments 10.28E and 9.21G, Incentive Pay

Q. Which adjustments have you reviewed that are contested by Staff?

A. The following six adjustments are contested by Staff:

- Adjustments 10.25E and 9.18G, Wage Increase
- Adjustments 10.26E and 9.19G, Investment Plan

- Adjustments 10.27E and 9.20G, Employee Insurance

Q. Are you sponsoring any Exhibits in support of your testimony?

A. Yes. I sponsor the following exhibits in support of my testimony:

- Exhibit No. JH-2, Staff Wage Increase Adjustments
- Exhibit No. JH-3, Staff Investment Plan Adjustments
- Exhibit No. JH-4, Staff Employee Insurance Adjustments.

III. DISCUSSION

A. Adjustments 10.25E and 9.18G, Wage Increases

Q. Please describe the Company's wage adjustments for union and non-union employees.

A. The Company estimated wage increases for both union and non-union employees to March 31, 2011. To make these estimates, the Company simply applied the same wage increases from 2009 to 2010 for both union and non-union employees.

Q. How long will the Company's current contracts run for both International Brotherhood of Electrical Workers ("IEBW") and United Association of Plumbers and Pipefitter ("UA") union employees?

A. The current contract for IEBW will run through March 31, 2010 and the UA contract will run through September 30, 2010.

Q. Please explain why Staff contests the Company's proposed adjustments for union and non-union employee wage increases?

A. The Company's proposed wage increase adjustment for union and non-union employees does not meet the Commission's criteria for a pro forma adjustment.

Q. What are the Commission's criteria for a pro forma adjustment?

A. WAC 480-07-510 specifies that pro forma adjustments "...give effect for the test period to all known and measurable changes that are not offset by other factors." Since the current contract for IEBW will run through March 31, 2010 and the current UA contract will run through September 30, 2010, any wage increase adjustment beyond March 31, 2010 for IBEW members and beyond September 30, 2010 for UA members is not known and measurable. Likewise, any wage increase for non-union employees beyond March 31, 2010 is also not known and measurable. The estimated wage increases to March 31, 2011 that are added to test year results by the Company are merely a boost to the revenue requirement for the Company.

Q. What is the basis for Staff's wage increase adjustments for union and non-union employees?

A. As stated above, potential wage increases beyond the current employee contract expiration dates are not known and measurable. Therefore, Staff adjusts wage increases to March 31, 2010 for non-union employees. Staff also adjusts wages increases to

March 31, 2010 for IEBW members and to September 30, 2010 for UA members according to the Company's current contract with those unions. This treatment ensures that Staff's wage increase adjustments for union and non-union employees are based on known and measurable changes that are not offset by other factors.

Q. Are there any other reasons for the Commission to reject the Company's Wage Increase Adjustments 10.25E and 9.18G?

A. Yes. There is a double counting error in PSE's calculation of its adjustments with regard to the percentage of wage increases to IBEW employees. First the Company proposed a 3.25 percent wage increase to IBEW employees from April 1, 2009, to March 31, 2010. Later, the Company also proposed a 3 percent wage increase to IBEW employees from January 1, 2010, to December 31, 2010. Therefore, the IBEW employees wage increase from January 1, 2010 to March 31, 2010, was counted twice, as can be seen in Company witness Story's Wage Increase Adjustment work papers.

To eliminate the double counting issue, I simply removed the Company's proposed 3 percent wage increase to IBEW employees from January 1, 2010, to December 31, 2010, leaving the increase in place from April 1, 2009, to March 31, 2010.

Q. What is the impact of Staff's Wage Increase Adjustments 10.25E and 9.18G?

A. For electric operations, Staff's adjustment increases expense by $2,760,576 and reduces net operating income by $1,794,374. For gas operations, Staff's adjustment increases expense by $1,804,282 and reduces net operating income by $1,172,783.

These amounts are calculated in Exhibit No. JH-2, Staff Wage Increase Adjustment. They are also reflected in Exhibit No. KHB-2, page 2.32 and Exhibit No. KHB-3, page 3.23, for the electric and gas operations, respectively.

Q. Did the Company include any adjustment for salary increases for executives?

A. No, the Company did not propose any wage increases for executives and did not make adjustment to the test year level of salary for the executives.

B. Adjustments 10.26E and 9.19G, Investment Plan

Q. Please explain Staff's Investment Plan adjustments.

A. The Investment Plan adjustments adjust the Company's portion of the investment plan expense to reflect the additional expense associated with wage increases. According to PSE's 401(k) Investment Plan, the Company makes matching contributions to employee's retirement. In addition, the Company contributes to each employee's retirement account in an amount equal to 1 percent of each employee's base pay. This adjustment merely reflects the increase in PSE's contribution to the investment plan, given Staff's recommended level of wage increases.

Q. What is the impact of Staff's Investment Plan adjustments?

A. For electric operations, Staff's adjustment increases expense by $142,370 and reduces net operating income by $92,541. For gas operations, Staff's adjustment increases expense by $86,220 and reduces net operating income by $56,043.

These amounts are calculated on Exhibit No. JH-3, Staff Investment Plan Adjustment. They are also reflected in Exhibit No. KHB-2, page 2.33 and Exhibit No. KHB-3, page 3.24, for the electric and gas operations, respectively.

C. Employee Insurance Adjustments 10.27E and 9.20G

Q. Please explain the Company's adjustments for Employee Insurance.

A. PSE uses a current Flex Credit amount per employee from 2009 to apply to 2010. The Company estimates that the Flex Credit amount per employee will be 8 percent, which is the same amount as used in 2009.

Q. Please explain why Staff contests the Company's adjustments for Employee Insurance.

A. PSE's proposed adjustments to Employee Insurance are estimates based on a forecast and, thus, they do not meet the Commission's criteria of a pro forma adjustment.

Q. Please explain Staff's adjustments for Employee Insurance?

A. Staff used the actual, negotiated Flex Credit amount per employee of 4.75 percent for 2010 to adjust Employee Insurance. This Flex Credit amount is based on known and measurable changes that are not offset by other factors.

For electric operations, Staff's adjustment increases expense by $1,191,560 and reduces net operating income by $774,514. For gas operations, Staff's adjustment increases expense by $643,303 and reduces net operating income by $418,147.

These amounts are calculated on Exhibit No. JH-4, Staff Employee Insurance Adjustment. They are also reflected in Exhibit No. KHB-2, page 2.34 and Exhibit No. KHB-3, page 3.25, for the electric and gas operations, respectively.

Q. Does that complete your direct testimony?

A. Yes, it does.