EXHIBIT NO. ___(DEM-12T)
DOCKET NO. UE-072300/UG-072301
2007 PSE GENERAL RATE CASE
WITNESS: DAVID E. MILLS

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
DAVID E. MILLS
ON BEHALF OF PUGET SOUND ENERGY, INC.

JULY 3, 2008

PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF DAVID E. MILLS

CONTENTS

PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF DAVID E. MILLS

I. INTRODUCTION

Q. Are you the same David E. Mills 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. ___(DEM-1CT), and seven exhibits supporting such direct testimony, Exhibit No. ___(DEM-2) through Exhibit No. ___(DEM-8C). On April 11, 2008, I filed supplemental direct testimony, Exhibit No. ___(DEM-9T), and two exhibits supporting such supplemental direct testimony, Exhibit No. ___(DEM-10) and Exhibit No. ___(DEM-11C).

Q. Please summarize the purpose of your rebuttal testimony.

A. This rebuttal testimony first responds to various statements and proposals for power cost adjustments and issues presented by other parties in this rate case. Specifically, this rebuttal testimony responds to two changes to rate year power cost adjustments proposed by the Staff of the Washington Utilities and Transportation Commission ("Commission Staff"). Second, this rebuttal testimony discusses updating power costs for more recent forecast gas prices for the rate year just prior to the Commission's order in a general rate case or PCORC. Finally, this rebuttal testimony requests a prudency determination on one additional contractual resource, the TransAlta Exchange Agreement, discussed in my prefiled direct testimony.

II. OVERVIEW OF POWER COST ADJUSTMENT PROPOSALS

Q. Please discuss Commission Staff's proposed adjustments to power costs.

A. Commission Staff proposes two adjustments to power costs that decrease rate year power costs by $12.5 million.

The first proposed adjustment is to reduce the model outage rate for the Colstrip Generating Units as a means to retain only the "normal" forced outage years. PSE disagrees with this approach, which arbitrarily removes certain years from the model outage rate calculation approved by the Commission in 1993 and used by PSE since that time. Although PSE believes that the current methodology for determining the model outage rate for Colstrip is appropriate, this rebuttal testimony provides a counterproposal to Commission Staff's forced outage adjustment.

The second proposed adjustment is to filter, or remove, certain hydro years as a means to reduce power costs. As discussed in this rebuttal testimony, this approach is contrary to the Commission's past directive that the cost of power included in rates should reflect what is expected to occur in the rate year. In addition to this rebuttal testimony, Dr. Jeffrey Dubin provides rebuttal testimony, Exhibit No. ___(JAD-1T), that addresses the use of a hydro filtering adjustment in determining power costs and provides support for the conclusion that Commission Staff's hydro filtering proposal is not appropriate in setting rates.

Q. What is Commission Staff's justification for its proposed power cost adjustments?

A. Commission Staff asserts that these power cost adjustments are appropriate because they provide "a more appropriate sharing of risk" given PSE's recent general rate cases, Power Cost Only Rate Cases ("PCORC") and Power Cost Adjustment ("PCA") mechanism filings. Exhibit No. ___T(APB-1T) at page 4, line 20.

Q. Do you agree with Commission Staff assertion that customers are bearing too much of the power cost risk?

A. No. Commission Staff concedes the rapidly rising cost of power supply but at the same time laments that customer rates have increased accordingly and that customers have covered $3.1 million of power cost deferrals under the PCA mechanism's initial six cycles ($1.8 million of deferrals plus interest). *See* Exhibit No. ___T(APB-1T) at page 5, line 18, through page 7, line 10.

Over the PCA history, through PCA Period 6, PSE has under-recovered cumulative power costs as high as $40.6 million and customers have been allocated costs as high as $25 million. After six cycles, PSE has absorbed $3.8 million in power costs. The risk is still weighted heavily towards PSE; however, both PSE and customers have benefited from the PCA mechanism. Although five-and-one-half years is a short period of time to develop a trend, especially given the volatility of power costs, it does seems appropriate that customers have paid for the cost of the power they have demanded and consumed during that period of time.

Q. Please discuss Commission Staff's other recommendations.

A. Commission Staff recommends that a deadline be set in future PCORCs for updates to power costs prior to other parties' response testimonies and that PSE submit a study and revision to the PCA mechanism prior to the filing of the next general rate case to better align the asymmetrical power cost distribution with the risks and benefits balanced between customers and shareholders. PSE agrees with both of these recommendations, with the clarification that in addition to the one update during the PCORC proceeding, the Commission should have power costs updated prior to rates going into effect to reflect the most recent gas price forecast possible as was done in PSE's 2006 general rate case, *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UG-060266, *et al*.

Q. Do you agree with Public Counsel's assertion that PSE easily modifies its power costs for rate recovery? *See* Exhibit No. ___(LS-1TC), page 22, lines 1-8.

A. Although it is true that PSE may update power costs for recovery in rates in either a PCORC or a general rate case filing, it is fallacy to imply that it is easily accomplished. PSE reviews all of the PSE-specific underlying assumptions of its AURORA power cost model, updates every calculation outside of the AURORA model with the most recent data, and reviews such data to ensure the inclusion of all rate year power cost issues. In addition, PSE is subject to audit from Commission Staff and receives extensive requests for power cost information from all parties during the course of a rate proceeding. Intervening parties spend numerous hours and re-model, analyze and dissect the rate year power costs, in many cases, providing new approaches to power cost modeling that PSE must consider and debate. Only after a thorough debate, or in some cases a settlement of the power costs in a proceeding, will the Commission allow the power costs to be set in rates.

Q. Public Counsel testifies that PSE hedges to protect the Company from significant risk. Do you agree with this characterization of PSE's hedging program?

A. No. This characterization ignores the fact that PSE's hedging program protects both the Company and its customers. By hedging in the forward energy commodity markets, PSE seeks to protect both customers and shareholders from a highly volatile energy market and provide opportunities to stabilize or even lower costs to customers. A company abstaining from a disciplined hedging program exposes itself to volatile wholesale energy prices, which introduces increased uncertainty related to the company's power cost exposure. The choice to not engage in some form of forward hedging program is, in essence, taking a commodity position by counting on spot market prices always being below that of the forward market. A hedging program managed in a disciplined manner can prove to be an effective tool for providing stable energy prices to customers. Hedging commodity risk in the forward markets prior to the beginning of the delivery month allows PSE to reduce exposure in its wholesale gas and power portfolios. When PSE is deficit resources to meet demand (also referred to a being "short"), the risk exposure is to rising market prices. When PSE has surplus resources to sell (also referred to as being "long"), the risk exposure is to falling market prices. By hedging, PSE can lock-in commodity prices and mitigate price exposure. An overarching principle behind PSE's hedging program is finding the balance between mitigating risk and stabilizing costs for customers.

Q. Did Public Counsel propose adjustments to power costs?

A. No. Public Counsel does not propose any adjustment to the rate year power costs filed in this proceeding; nor do any other intervenors.

III. COLSTRIP MODEL OUTAGE RATE

Q. Please describe Commission Staff's proposed adjustment to the Colstrip Units' model outage rates.

A. Commission Staff proposes an adjustment that "does not provide a set methodology to determine model input" to the Colstrip Units' model outage rates to reflect a "normal" range of historical forced outages. Exhibit No. ___T(APB-1T) at page 13, lines 4-5. This type of adjustment is somewhat troublesome because it has no methodology for replicating the adjustment going forward. Mr. Michael Jones discusses several other reasons why this adjustment is inappropriate in his rebuttal testimony, Exhibit No. ___(MLJ-15T).

Q. Does PSE propose an adjustment to the Colstrip units' model outage rates?

A. Yes. As discussed in the rebuttal testimony of Mr. Jones, PSE believes that the seven-year average outage rate that has been in effect since 1993 is appropriate; however, PSE is proposing to use a four-year average of the historical forced outages to eliminate any concerns that use of the seven-year average delays customers' receipt of the benefits of the most recent improvements to Colstrip.

Q. Please explain the change to projected rate year power costs due to the Colstrip model outage rates change.

A. In this rebuttal filing, PSE revised the historical forced outage rating period included in the power costs in the April 2008 supplemental filing from a seven year to a four year average. The Colstrip model outage rates changed from 8.55% to 9.70% for Colstrip Units 1 and 2 and from 10.38% to 7.91% for Colstrip Units 3 and 4. PSE also adjusted the generation for the Northwestern Energy contract accordingly because its contractual generation is directly synched to the availability of Colstrip Units 3 and 4. Forecast rate year power costs are reduced $3.7 million, as shown in Exhibit No. ___(DEM-13C). PSE included this decrease in power costs in the revenue requirement sponsored by Mr. John Story.

Q. Would PSE's proposed Colstrip adjustment change if power costs were updated?

A. Yes. The $3.7 million adjustment is based upon PSE's April 2008 supplemental filing, which includes fifty years of average hydro generation and three-month average gas prices at March 11, 2008. If the Commission were to accept PSE's Colstrip model outage rates adjustment and were to further order power cost adjustment or updates, the impact of the Colstrip model outage rates adjustment should change.

IV. WATER FILTERING ADJUSTMENT

Q. Before you comment on Commission Staff's proposed water filtering adjustment, please describe how hydro generation data affect rate year power costs.

A. During an average streamflow year, approximately thirty percent of PSE's electric energy production is from hydroelectric resources. These resources include both PSE's contractual rights under its Mid-Columbia ("MidC") contracts and its owned hydroelectric projects: the Snoqualmie Falls Project, the Upper Baker Project, the Lower Baker Project, and the Electron Project. PSE interacts in a marketplace such that market prices are low when hydro energy is abundant and market prices are disproportionally higher when hydro conditions are poor. This creates a skewed distribution of power costs across various hydro conditions.

To consider the power cost impact from this volatile, yet highly valued resource, PSE uses fifty years of historical streamflow data to model hydroelectric generation. The fifty years of hydro generation is input to the AURORA model. The AURORA model—a fundamentals-based hourly production cost model—relies on factors such as supply resources and regional demand for power and transmission to simulate competitive wholesale power markets in which the regional fleet of generating resources is dispatched to meet regional electric loads. AURORA develops fifty model results—one for each of the fifty hydro years. The average of these fifty AURORA model runs is the AURORA model normalized power costs and generation for the rate year.

Q. Please explain Commission Staff's proposed water filtering adjustment.

A. Commission Staff proposes to remove power costs associated with hydro generation that is beyond one standard deviation from the average of the fifty hydro years' generation. In doing so, rate year power costs are reduced.

Commission Staff claims that this adjustment is intended to "more appropriately share[s] risk when developing normalized base power costs" and to align "the methodology for determining base power supply costs with a regulatory environment that includes an annual PCA." Exhibit No. ___T(APB-1T) at page 5, lines 2-3, and at page 13, lines 20-23. Staff notes this proposal is warranted only because PSE has a PCA mechanism in place. Staff's errant water filtering adjustment is discussed extensively in the rebuttal testimony of Dr. Jeffrey Dubin, Exhibit No. ___(JAD-1T).

Q. Do you agree with Commission Staff's theoretical basis for a water filtering adjustment?

A. No, power costs should be calculated using agreed upon methodologies and regulatory precedents. The existence of a PCA mechanism is irrelevant when setting base rates. If a PCA mechanism is in place and if the PCA indeed shifts risk from the shareholders to the ratepayers, it is the underlying conditions of the PCA mechanism itself (i.e., sharing bands and procedures) that should be adjusted to more appropriately balance risk between shareholders and customers—not the underlying power costs. Staff's proposal merely biases the rate year power costs against the shareholders.

As mentioned above, PSE agrees with Commission Staff's proposal to study the PCA mechanism to ensure the risks are aligned between customers and shareholders. It should be during this analysis that power cost risks—including hydro volatilities—will appropriately be considered in determining the proper PCA sharing bands.

Q. What is the underlying philosophy for the forecast of power costs that will be included in rates?

A. The cost of the power included in rates should reflect what is expected to occur in the rate year. As noted below, the best estimate, for ratemaking purposes, of what hydro generation will be in the rate year is premised on an average of actual historical hydro generation data, using at least fifty years of data.

In addition, the PCA mechanism is intended to be a balanced mechanism—one that should result in roughly an equal chance of under- or over-recoveries for both shareholders and customers. In other words, a PCA mechanism should, on average, be revenue neutral. An estimate of the baseline rate that is biased, as Commission Staff has proposed, neither reflects what shareholders and customers can expect to occur in the rate year nor cures any possible design deficiencies in the PCA mechanism. It is the PCA mechanism itself that may require adjustment—the methodology by which rate year power costs are determined does not need adjustment.

Q. Has the Commission supported this philosophy?

A. Yes. The Commission has recognized this inherent philosophy in setting the PCA baseline rate:

> If the power cost baseline is set too low relative to actual prices, the greater the burden of those consequences for PSE's shareholders. Similarly, if the power cost baseline is set too high, ratepayers are burdened by the fact that they are paying more for power than what they should be paying. The PCA mechanism was meant to be fair to both shareholders and ratepayers.
>
> In summary, as we examine the power cost baseline from time to time—recognizing that it is important that we undertake that examination on a regular basis—we must strive to determine, with the greatest degree of precision that forward looking models can produce, an accurate estimate of actual costs that PSE will experience in the near and intermediate terms. It is a challenging task to estimate what the Company's actual costs of power will be in future periods, yet that is what we must strive to do so that the PCA mechanism functions, as intended, to balance the risk of excursions in power costs as equally as possible between ratepayers and shareholders.
>
> We resolve the philosophical question raised by ICNU in favor of the practical conclusion that power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings.

WUTC v. Puget Sound Energy, Inc., Docket Nos. UE-040640, *et al.*, Order 06 at ¶ 106-108 (Feb. 18, 2005).

Q. Are there other risks included in the rate year forecast power costs that should be considered when developing a PCA mechanism?

A. Yes. In establishing the PCA power cost baseline rate, it is reasonable to normalize many of the inherent variabilities to power costs. Rate year power costs include what is expected for each of the drivers based upon the best information available: (1) weather uncertainty assumes a single forecast of normal temperatures and load; (2) market variations in gas prices assumes a three-month average monthly gas price forecast which does not vary during the rate year; (3) forced outages are based on historical averages; and (4) wind generation is based on average modeled historical information. A normal, or expected, power cost associated with these risks is included in the rate year power costs, along with the expected, or normal, hydro generation.

Q. Is water filtering just another way to normalize hydro generation?

A. No. Water filtering is simply a variation of the argument to eliminate low water years from determining average available resources so as to artificially maximize a low cost resource and lower power costs when setting rates. Hydro generation is very difficult to forecast; therefore, analysts use historical streamflows to determine future hydro generation. The issue of the years of hydro generation that should be included in the modeling of power costs for the rate year has been debated as far back as I can recall.

The most recent analysis of the hydro streamflow and generation data was performed in PSE’s 2004 GRC by Commission Staff Dr. Yohannes Mariam and by PSE’s consultant, Dr. Jeffrey Dubin. As discussed in the rebuttal testimony of Dr. Dubin in this proceeding, the outcome of this extensive analysis—which stands in stark contrast to Commission Staff's analysis in this rate proceeding—was that *at least* fifty years of hydro information should be used when determining power costs for rate purposes.

Commission Staff, in this proceeding, would take a giant step backwards because its proposal considers only thirty years of hydro information. This is discussed in more detail in Dr. Dubin's rebuttal testimony. In short, water filtering is not normalizing hydro information.

Q. Commission Staff has proposed improvements to the PCORC process and the Industrial Customers of Northwest Utilities ("ICNU") has expressed concerns about the complexity of the power cost projections. Does water filtering help with either of these issues?

A. No. Forecasting the rate year power costs would be even *more* complicated if a hydro filtering adjustment was implemented. ICNU claims the review of power costs in rate proceedings is difficult now—water filtering will only make it more difficult by adding steps before power costs may be determined.

For example, to determine the hydro years to include in the AURORA model runs, PSE's annual hydro generation data for each of the fifty water years would need to be calculated and sorted, the standard deviation determined and the water years falling outside of one standard deviation removed. At that point, the AURORA model would be run with the hydro years falling within one standard deviation to generate an average model run to determine average rate year generation by resource, as this information is used throughout the power cost and production operations and maintenance expense calculations. Regardless, as pointed out in the rebuttal testimony of Dr. Dubin, there is no logical basis as to why one standard deviation around the annual hydro generation is appropriate.

Q. Does Commission Staff correctly calculate the water filtering methodology it proposes?

A. No. Commission Staff summed the total monthly average megawatts of MidC generation for each of the water years, rather than using an average megawatt for the year. Additionally, Commission Staff utilized the entire MidC generation for each of the water years without considering the fact that PSE has varying contractual shares of the generation from the MidC hydro projects. It is PSE's share of the generation of the MidC projects generation that directly affects PSE's power costs in the AURORA model runs, not the total MidC project generation (although total MidC generation does impact regional market prices).

Q. Did Commission Staff utilize all of PSE's hydro generation data in their water filter calculation?

A. No. Commission Staff did not consider PSE-owned hydro generation. Like the MidC generation data, fifty years of generation data is input to the AURORA model for PSE-owned hydro projects: the Snoqualmie Falls Project, the Upper Baker Project, the Lower Baker Project, and the Electron Project. The varying fifty years generation of these projects is included with PSE's share of the MidC generation when running each of the fifty AURORA model runs.

Q. Do you have a correction to Commission Staff's hydro filtering adjustment to reflect these issues?

A. If Commission Staff had used all of, and only, PSE's hydro generation in its hydro filter calculation, the hydro filter adjustment would have resulted in a $7.413 million reduction to PSE's rate year power costs, rather than the $9.380 million calculated in Commission Staff's Exhibit No. ___(APB-4C). Please see Exhibit No. ___(DEM-14C) for a correction of Commission Staff's calculation. PSE is not agreeing that this calculation is appropriate by presenting this correction but is simply showing that Commission Staff did not take into consideration the hydro available to PSE in what is, nonetheless, an inherently flawed analysis.

V. UPDATE POWER COSTS TO REFLECT MORE RECENT GAS PRICES

Q. Is PSE providing an update to the projected power costs filed in April 2008?

A. No. Other than the power cost reduction to reflect the Colstrip model outage rate calculation, PSE is not filing updated power costs at this time.

Q. Should the rate year power costs be updated before the new rates go into effect?

A. Yes. The Commission has made clear in PSE's two most recent general rate cases that the "power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings," *WUTC v. Puget Sound Energy, Inc.,* Docket Nos. UG-040640, *et al*., Order 06 at ¶ 108 (Feb. 18, 2005), and "the Power Cost Baseline Rate is the expected level of power costs around which the Company's power cost adjustment mechanism works," *WUTC v. Puget Sound Energy, Inc.,* Docket Nos. UE-060266, *et al*., Order 08 at ¶ 99 (Jan 5, 2007). In this regard, the rate year power costs should be updated to reflect more recent gas prices, just prior to rates going into effect, so that they reflect the best estimate of the costs to be incurred in the rate year.

Q. How are the rate year power costs updated to reflect more recent gas prices?

A. The rate year gas price forecast input to the AURORA model should reflect a three-month average gas price as close as possible to the rate effective date. Rate year short-term fixed-price power and gas for power contracts at such date should also be included in the determination of the power costs. The short-term fixed-price power contracts are an AURORA input and the gas for power contracts are an adjustment included in the "Not in Models" calculation. In addition, several of the "Not in Models" adjustments and production operations and maintenance adjustments are dependent on the AURORA generation and prices. These adjustments update automatically in the MS Excel files whenever a new AURORA model run download is included in the files.

Q. Does PSE have an estimate of the impact to power costs with updated gas prices?

A. Yes. PSE calculated the three-month average gas price for the rate year as of May 27, 2008, and updated the AURORA model to reflect these prices. For purposes of comparison, the three-month average gas price at the Sumas trading hub for the rate year as of May 27, 2008 is $9.82 per MMBtu, as compared to the April 2008 supplemental filing's March 11, 2008 average of $8.51 per MMBtu. Considering (i) the updated AURORA model run using the updated gas prices and fixed rate year power contracts at May 27, 2008, (ii) the Not in Models update for fixed rate year gas for power contracts at May 27, 2008, and (iii) the resulting impacts to the Not in Models and Production O&M calculations due to an updated AURORA model run, rate year power costs are forecast to increase $18.5 million, from $1,148.7 million to $1,167.1 million. Please see Exhibit No. ___(DEM-15C) for a graph of the rate year forecast gas prices.

Q. What factors have affected the rise in natural gas prices?

A. The increase to natural gas prices is a current hot topic. Fundamental factors influencing the overall rise in global energy prices, directly affecting natural gas prices, are shown below. Most all contribute to increased prices, but some of these factors help to mitigate the price increases:

i. Global competition and demand for energy;

ii. Record high oil prices and geopolitical risk;

iii. Liquefied natural gas becoming a more important source of supply;

iv. Year on year natural gas storage decline;

v. Increasing gas demand for power generation;

vi. Increasing U.S. natural gas production;

vii. Canadian imports below historic levels;

viii. Weather uncertainty (hurricanes and cold weather); and

ix. Expected increases in prices in the West due to the Rockies Express Pipeline.

Q. Have gas prices continued to rise?

A. Yes. Although the rate year three-month average gas price as of May 27, 2008 was $9.82 per MMBtu, the average rate year gas price at that date was $11.05 per MMBtu. A more recent forecast date, June 13, 2008, shows (i) gas prices continue to rise, (ii) the calculation of the three-month average gas price for the rate year to be $10.16, and (iii) the average gas price for the rate year at that date to be $11.48 per MMBtu. Please see Exhibit No. ___(DEM-15C) for the rate year forecast gas price graph that reflect these data.

VI. TRANSALTA EXCHANGE CONTRACT

Q. Please describe the TransAlta Exchange contract.

A. As discussed in my direct testimony in this proceeding, PSE signed a three-and-a-half year Locational Exchange Agreement with TransAlta Energy Marketing (US)

Inc. (totaling 4,718,575 Megawatt Hours).

Q. Did PSE provide information to determine the prudency of this contract in your direct testimony?

A. Yes. My direct testimony presented discussion and support for the reasonableness of this contract. PSE now requests that the Commission provide an appropriate prudency determination.

Q. Was this contract included in the new power contracts deemed prudent by Commission Staff?

A. No. The direct testimony of Ms. Kimberly Harris inadvertently excluded this long-term contract from the listing of new resources and new contracts requiring prudence review.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.