EXHIBIT NO. ___(SA-1CT)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: SALMAN ALADIN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-06____ Docket No. UG-06____

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
SALMAN ALADIN
ON BEHALF OF PUGET SOUND ENERGY, INC.

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VERSION

FEBRUARY 15, 2006

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy, Inc.

A. My name is Salman Aladin. My business address is 10885 N.E. Fourth Street Bellevue, WA 98004. I am the Director of Structuring, Asset Optimization and Analytics for Puget Sound Energy, Inc. ("PSE" or "the Company").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(SA-2).

Q. What are your duties as Director of Structuring, Asset Optimization and Analytics for PSE?

A. My responsibilities include oversight of the Structuring and Asset Optimization and Portfolio Analytics Departments. These departments engage in ongoing modeling and analyses that is intended to help the Company better optimize its electric and natural gas portfolios in the medium-term (up to two years), through wholesale power and natural gas market purchases and sales. My responsibilities overlap with those of Mr. David Mills. Both Mr. Mills and I work to develop strategies to address risks related to the Company's electric and gas portfolios. While Mr. Mills tends to focus on implementation of portfolio risk management strategies, I focus more on analysis and modeling of these risks.

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

A. My testimony first describes the challenges facing the Company in managing its electric and natural gas portfolios as well as the cost of the power and natural gas consumed by PSE's customers. I focus in particular on the significant volatility and risk inherent in the Company's electric portfolio due to factors (such as streamflow variation affecting the supply of hydroelectric generation and weather uncertainty) that make it very difficult to predict the amount of power PSE's resources will produce and PSE's electric customers will use.

I describe modeling work the Company has performed in order to better understand the magnitude of potential variations in power costs above or below a baseline power cost rate that is projected at the time of a rate case and embedded in PSE's electric rates.

My testimony then describes the Company's proposed revisions to its existing Power Cost Adjustment ("PCA") Mechanism in this case with respect to the sharing of power cost risks between the Company's customers and shareholders. I explain why PSE's proposal is fair, from a risk perspective, and will result in risk sharing that better aligns the interests of the Company's customers and shareholders. I also show, using the Company's modeling methodology, the projected impact of PSE's proposed revised sharing structure.

II. VOLATILITY AND RISK IN PSE'S ELECTRIC AND NATURAL GAS RESOURCE PORTFOLIOS

Q. Is energy risk management a concern to the Company?

A. Yes, absolutely. PSE's resource portfolio is subject to significant volatility and risk that ultimately have a substantial impact on energy costs. This is a reason the Company has an entire area of the Company devoted to energy risk management, as described in the testimony of Mr. David Mills.

Q. What drives this volatility and risk in the natural gas portfolio?

A. The Company's gas supply portfolio is composed of a mix of supply contracts from various producing areas, including the Western Canadian Sedimentary Basin, the Rocky Mountain area, and the San Juan Basin. Mr. Eric Markell describes PSE's gas portfolio in his direct testimony, Exhibit No. ___(EMM-1HCT). The major drivers of gas cost volatility for the Company are load, temperature and market prices for natural gas.

The Company has price risk associated with the expected volume of its purchases and sales of natural gas in the wholesale markets due to volatility of the market price for gas at the various supply points. In addition, the level of the Company's retail natural gas demand is closely correlated to temperature. Variations in natural gas demand caused by temperature-related load variation need to be addressed through gas storage and transactions in the wholesale gas markets.

Q. How is the Company proposing to address these risks and cost volatility in this case?

A. The Company proposes to continue the current Purchased Gas Adjustment ("PGA") Mechanism, with a slight modification related to passing through the costs of a new line of credit to support the Company's natural gas hedging efforts. This proposal is described in the direct testimonies of Mr. David Mills, Exhibit No. ___(DEM-1CT), and Mr. Karl Karzmar, Exhibit No. ___(KRK-1T).

PSE is also proposing to address risks related to variations in gas load through the decoupling mechanism described in the testimony of Mr. Ron Amen, Exhibit No. ___(RJA-1T).

Q. What drives volatility and risk in the power portfolio?

A. PSE's power supply portfolio contains a diverse mix of resources with widely differing operating and cost characteristics. Mr. Eric Markell describes PSE's power supply portfolio in his direct testimony. Although there are many complex variables embedded in the portfolio, the major drivers of power cost volatility are: (1) streamflow variation affecting the supply of hydroelectric generation; (2) weather uncertainty affecting power usage; (3) variations in market conditions such as wholesale gas and electric prices; (4) risk of forced outages; and (5) transmission and transportation constraints. All of these create load and resource volatility, which PSE balances with wholesale market purchases and sales (as described in the testimony of Mr. David Mills).

Q. Please describe the volatility related to variations in hydroelectric supply.

A. During an average streamflow year, approximately one-third of PSE's electric energy production comes from hydroelectric sources. During poor streamflow conditions, PSE may need to acquire replacement power to serve its customer load. During favorable streamflow conditions PSE may need to sell surplus power to balance its supply portfolio and mitigate its power costs. These balancing transactions are conducted in the wholesale power markets. Because the market price of power is quite volatile, hydroelectric shortfalls or surpluses can greatly affect PSE's power costs.

Q. Please describe the volatility that is related to load and temperature uncertainty.

A. The Pacific Northwest region has a high saturation of electric space heating relative to other areas of the country. As a result, the level of PSE's retail electric load is closely related to temperature – meaning that during the winter heating season PSE's load increases as the weather gets colder. In light of the significant electric heating load in PSE's service territory, PSE's cost of load/temperature uncertainty can be significant.

Q. Please describe the risks related to market prices.

A. Even absent the foregoing volume-related risks, which affect the amount of PSE's exposure to market prices, PSE has significant price-related risk associated with the expected volume of its purchases and sales of power in the wholesale markets and its need to purchase or dispose of natural gas in connection with the operation of its gas-fueled generating units.

Q. Please describe the volatility related to forced outages.

A. PSE relies on more than 2,100 MW of nameplate thermal generating units to help meet its customer loads. These units include approximately 677 MW of large base load coal generators with low variable fuel costs; approximately 827 MW of gas combined cycle combustion turbine cogenerators with moderate heat rate conversions; and approximately 596 MW of relatively less-efficient, simple-cycle gas and oil-fired combustion turbine generators. Forced outages at any of these units can expose PSE to significant price volatility in its power supply portfolio. Material or equipment failure, fire, electrical disturbances, forced outages at generating projects, or other force majeure events typically cause forced outages.

Thermal Generation Units

	Capacity (MW)
Coal	677
Fredrickson CC	134
Encogen	170
NUGS	523
Simple Cycle CTs	596
	2100

Q. What risks are related to transmission and transportation constraints?

A. Pipeline outages and curtailment of transmission rights due to deratings[1], planned outages or forced outages are examples of transmission and/or transportation risk. For example, if power cannot be wheeled[2] from the Mid-Columbia trading hub ("Mid-C"), the Company may dispatch resources that are less economic in order to meet demand.

Q. Are PSE's power and gas costs subject to other risks?

A. Yes, examples of other risks include:

- counterparty risk, which is the risk of default by PSE's counterparties on contractual obligations; and
- execution risk, which is the ability to execute wholesale market transactions. Market liquidity, counterparty credit requirements and contractual requirements are examples of execution risk.

Mr. David Mills discusses these issues in his testimony.

Q. How was power cost volatility dealt with in the resolution of the Company's 2001 general rate case?

A. In response to significant price volatility, uncertainty in the wholesale energy markets and PSE's need to add resources to meet its load obligations, the parties

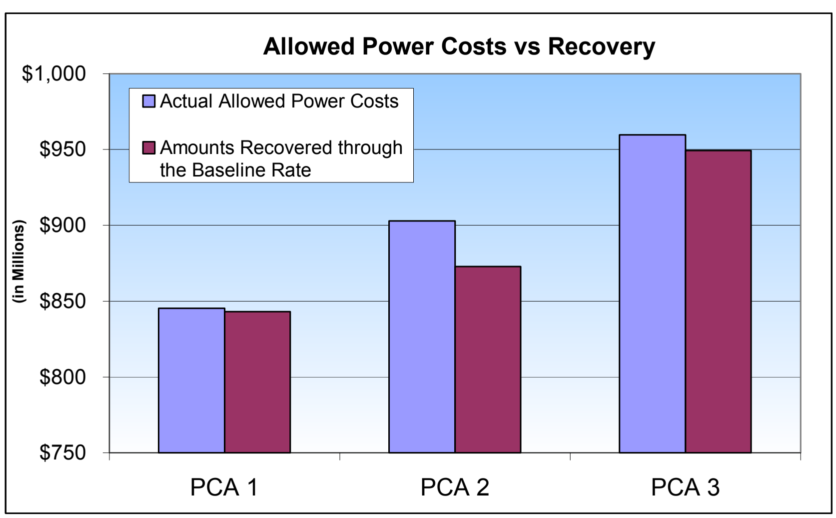
[1] Derating means decreasing the rated electric capability of an electric transmission line.

[2] Wheeling means using the transmission facilities of one power system to transmit power of and for another system. This term is often used colloquially to mean transmission.

who participated in the Power Cost Adjustment Collaborative agreed to a negotiated PCA Mechanism in 2002. The PCA Mechanism set forth an annual accounting process for a sharing of costs and benefits between PSE and its customers over four graduated levels (so-called "bands") of power cost variances on the first $120 million of power cost variances, with a $40 million (+/-) cap on PSE's potential exposure over a 4-year period ending June 30, 2006. On power cost variances over the $40 million cap, the PCA sharing mechanism allocated 99% of costs or benefits to customers and the remaining 1% of costs or benefits to PSE. The Commission approved the PCA Mechanism in its Twelfth Supplemental Order, Docket Nos. UE-011570 and UG-011571 (June 20, 2002) at 11-15.

Q. What has been PSE's experience with the PCA Mechanism since it was implemented?

A. PSE's power costs exceeded the amounts recovered through the Power Cost Baseline Rate during the first three PCA periods as shown in the following chart:



The primary drivers of this under-recovery were variations in hydro, prices and load from those figures assumed in PCA Power Cost Baseline Rates.

In addition, actual market heat rates during each PCA period were less than forecast in the PCA Power Cost Baseline Rates. In other words, it was more cost-effective to purchase power than natural gas for power generation purposes. This resulted in a reduced quantity of generation at PSE's gas-fired generation plants, which in turn reduced the level of secondary sales transactions and increased the level of secondary purchase transactions that PSE made.

See generally PSE's 2003 PCA Annual Report, Docket No. UE-031389 (filed August 28, 2003); PSE's 2004 PCA Annual Report, Docket No. UE-041570 (filed August 31, 2004); PSE's 2005 PCA Annual Report, Docket No. UE-051314 (filed August 31, 2005).

Q. Is the Company proposing to change the PCA Mechanism?

A. Yes. The Company is suggesting certain revisions be made to the PCA Mechanism, as set forth in the testimony of Mr. John Story. These proposed revisions include changes to the existing sharing bands, as discussed below.

Q. How did the Company develop its proposed change to the sharing bands?

A. The Company first sought to understand the magnitude and variability of power cost and earnings per share risks associated with PSE's power cost portfolio through developing and conducting the modeling described below. The Company felt it was important to reevaluate these risks given the upcoming June 30, 2006 expiration of the $40 million cap.

The Company developed its proposed changes to the sharing bands based upon the information produced through this modeling, and considerations of equitable sharing of costs, given the magnitude of costs that the Company reasonably can control and those it cannot.

III. MODELING THE POWER COST RISKS OF PSE'S ELECTRIC PORTFOLIO

Q. How did the Company approach the project of modeling the magnitude of power cost risks associated with PSE's electric portfolio?

A. PSE sought to develop a methodology for modeling power cost risk associated with its electric portfolio that would be transparent to other parties and would incorporate to the extent possible techniques and methodologies that had been approved in prior Commission proceedings.

Q. How did the Company conduct the modeling?

A. PSE started with the AURORA model because it is familiar to the Commission and other parties. The AURORA model is a fundamentals-based hourly production cost model that relies on factors such as supply resources and regional demand for power and transmission to simulate competitive wholesale power markets. AURORA simulates, on an hourly basis, economic dispatch of the regional fleet of generating resources to meet regional electric loads, based on input fuel prices, other variable operating costs, inter-regional transmission limitations and other factors. AURORA thereby produces a forecast of the variable operating costs for the Company's generating resources, as well as a forecast of wholesale power prices.

For its modeling project, PSE utilized the Monte Carlo feature of AURORA that permits AURORA to run many different simulations by adjusting the base case input data in AURORA databases for hydro availability, fuel prices and load.

Q. What assumptions did the Company input into AURORA as a starting point for its Monte Carlo simulation?

A. The Company used the AURORA databases from the 2005 PCORC as the basis for the analysis. With respect to the hydro input, the Company used the average of the 50-year set of data from 1929 to 1978 that the Commission approved for power cost projections in the Company's 2004 general rate case and that was used in the 2005 PCORC case. For natural gas prices, the Company used the average forward market prices for the three month period ending April 29, 2005. These prices were used to generate the final power costs approved in the 2005 PCORC. All power cost and other results included in these analyses were for the PCORC rate year period of December 2005 through November 2006.

Q. Why were the 2005 PCORC databases and rate year period used as the basis for these analyses rather than the databases and rate year period for this 2006 general rate case?

A. The analyses described in this testimony were largely completed before the power cost modeling for the 2006 general rate case was finalized. Also, other parties involved in the Company's rate proceedings have already had the opportunity to review the input data and other assumptions used in the 2005 PCORC AURORA run, and thus, are in a better position to focus on the Monte Carlo aspect of the Company's modeling, rather than the AURORA inputs themselves.

Q. What did the Company do next?

A. A Monte Carlo risk file was developed to represent the variability and risks of the Company's power supply portfolio. The input distribution and variability data included in this file are based on an historical assessment of the distributions, variability, and correlations of historic hydro availability, gas prices, and Company loads. The hydro risk data is based on the 50-year hydro data used in the 2005 PCORC. The gas price risk inputs were based on actual gas prices over the August 2001 – April 2005 period.

To generate load scenarios, the Company developed scenarios dependent upon the same 50 year time period used for the hydro scenarios and with a mean the same as that accepted in the 2005 PCORC. Temperature data from 1929 to 1978 and the mean 2005 PCORC loads were used as inputs into PSE's load forecasting model to derive the load scenarios. From these 50 scenarios, the standard deviation and correlation for each month was calculated and used as input parameters for the AURORA run.

Q. What were the results of the AURORA Monte Carlo modeling?

A. The AURORA Monte Carlo simulation feature produced 1,100 simulations, 35 of which were determined to be outliers and were removed. Following is a distribution of PSE's electric portfolio power cost imbalances (over/under) recoveries) derived from these 1,065 simulations using the 2005 PCORC baseline rate of $52.503.

Chart Redacted

[redacted]

[redacted].

Q. Did the Company attempt to verify the accuracy of the AURORA modeling?

A. Yes. As a check on the AURORA Monte Carlo simulation, the Company manually ran twenty five scenarios in AURORA based on historical hydro conditions, load and historical forward gas prices. My Exhibit No. ___(SA-3) explains the methodology the Company utilized. By employing this process, the Company expanded its understanding of power cost variability and confirmed that actual historical situations produce a range of results very similar to those generated by the AURORA Monte Carlo simulations.

Q. What were the results of these 25 manual AURORA runs?

A. The results track the Monte Carlo simulation output, as shown in the diamonds on the below graph, which are placed on top of the Monte Carlo simulation curve already shown above:

Chart Redacted

Q. Has the Company approached modeling power cost risks in other ways?

A. Yes. The Company was also interested in exploring the extent to which hydro variability drives power cost risk in its electric portfolio, in part to determine whether a hydro tracker might be developed as part of or instead of the existing PCA Mechanism. A key question was: If hydro variability could be fully hedged, to what extent would that reduce or eliminate power cost volatility?

Q. Was the Company able to answer that question?

A. Yes. To run the initial 1,100 simulations in AURORA, a risk file is set up that contains specific parameters for hydro. To run the 1,100 simulations without hydro risk, these input parameters were simply removed, forcing the use of average hydro conditions in each simulation.

Q. What were the results of this modeling?

A. The Company found that even if hydro could be perfectly forecast and/or the costs of lower than forecast hydro passed through to customers, significant risk remained in PSE's portfolio. Of the 1,100 scenarios run without hydro variability, 4 were determined to be outliers and were excluded. The following chart compares these two simulations, with and without hydro variability.

Chart Redacted

As the graph illustrates, elimination of hydro risk would reduce the chance of extreme potential downside of bad water years. While overall risk would be reduced to a small degree, there is still a substantial amount of risk that the Company must manage due to factors other than hydro.

Q. Are these results expected?

A. It may seem surprising that elimination of hydro risk does not more significantly reduce potential power cost volatility. However, this points out the extent to which volatility is also driven by variations in loads, which are heavily weather dependent, and by natural gas prices.

Q. To what extent can the Company address some risks in the portfolio?

A. As a practical matter, the Company can reduce power cost exposure to some extent in the near term through the types of hedging activities described in Mr. Mills' testimony. Such hedging can be expected to reduce the power cost imbalance variability shown above for the "without hydro variability" distribution more than it can be expected to reduce the power cost imbalance variability shown above for the "with hydro variability" distribution. This is largely because the Company cannot effectively hedge the hydro exposure in its portfolio.

Q. Has the Company explored whether hedges are available for streamflow variation?

A. Yes, PSE has explored this question. However, based on my group's experience, no interested hedging counterparty has been capable of proposing a structured product that successfully addresses this type of risk while retaining the necessary requirement of cost effectiveness. Moreover, the unwillingness of counterparties to propose products that do not contain extreme risk premiums raised some interesting questions.

Q. What do you mean?

A. In my mind, this highlights a troubling disconnect between the theoretical academic or rate-making world and what actually transpires in the market. For example, while PSE's power costs for a rate year are projected using the average of a 50-year hydro data set, the potential counterparties that PSE has solicited to hedge streamflow variation have embedded a rather large downward skew in hydro. That is, they have embedded in their proposed products such low hydro flow that the hedge would be of little practical value.

Q. Has the modeling you describe above impacted the Company's thinking about power cost risks and the PCA Mechanism?

A. Yes. With the expiration of the $40 million cap on excess power costs, it is especially important that the sharing bands in the PCA Mechanism be fair to both shareholders and customers and that the Company is exposed to a level of power costs that is financially tolerable, as described in the testimonies of Ms. Kimberly Harris and Mr. Bertrand A. Valdman. The Company's proposed revisions to the PCA Mechanism sharing bands were designed with that in mind.

Q. What is the variability in the Company's earnings per share under the current sharing mechanism without the $40 million dollar cap?

A. The distribution of power costs from the AURORA Monte Carlo simulation discussed earlier was used to calculate a distribution around earnings per share as well as around power costs. [redacted].

IV. PSE'S PROPOSED REVISIONS TO POWER COST RISK SHARING UNDER THE PCA MECHANISM

Q. What revisions does the Company propose to the current PCA sharing bands?

A. In the absence of the $40 million cap, the current PCA Mechanism has the following annual sharing bands:

Power Costs ($ in millions) (over or under the PCA baseline)	Customers' Share	Shareholders' Share
$0 - $20 +/-	0%	100%
$20 - $40 +/-	50%	50%
$40 - $120 +/-	90%	10%
> $120 +/-	95%	5%

The Company is proposing in this case that the annual sharing bands be revised to the following:

Power Costs ($ in millions) (over or under the PCA baseline)	Customers' Share	Shareholders' Share
$0 - $25 +/-	50%	50%
$25 - $120 +/-	90%	10%
> $120 +/-	95%	5%

Q. Why is the Company proposing the revised band ranges and breakpoints?

A. The first $25 million band and its 50/50 sharing percentage is meant to more fairly share the power cost risks in PSE's portfolio associated with hydro variability. As shown in the chart below, this $25 million reflects approximately 65% (one standard deviation) of power cost risks with respect to PSE's hydro variability when considered on a stand alone basis. In other words, two years out of three, one would expect hydro variability to increase or decrease power costs by $25 million or less.

Chart Redacted

Q. Why is the Company proposing to share the excess power costs or power cost savings in this first $25 million tranche 50/50 rather than treating it as a "dead band" in which the shareholders absorb 100% of excess power costs or retain 100% of the benefits of power cost savings?

A. As described above, power cost risks in PSE's portfolio are significant, some of which – particularly hydro availability – PSE is incapable of hedging at a cost-effective price. Under the current sharing mechanism, PSE can be exposed to a large portion of the hydro risks and gains. Because hydro risk cannot be controlled or hedged, these risks theoretically should be passed through to customers 100%.

However, recognizing that PSE's electric portfolio is dynamic, that PSE does seek to make adjustments for the availability of hydro through use of its other generation resources and wholesale market purchases and sales, and that it is difficult to isolate and track the power cost effects of hydro, PSE is proposing that the Company's shareholders share the exposure within this first $25 million band equally with the Company's customers. By sharing this first band 50/50, shareholders and customers will typically share equally in the upside of good hydro years and the downside of bad hydro years.

Q. Are there other reasons to eliminate the current $20 million dead band?

A. Yes. The probability that there will be excess power costs or power cost savings is heavily dependent on how the PCA power cost baseline rate is set. In order for there to be a reasonably equal probability that costs will be lower or higher than the baseline by an equal magnitude, the PCA power cost baseline must be set so that it is at the midpoint of the range of potential power costs.

Setting a level of future expected power costs is a very inexact endeavor in that it is so heavily dependent on assumptions and forecasts that will inevitably turn out to be different from future conditions. It is the Company's hope that elimination of a dead band and a 50/50 sharing of the first $25 million of power costs will align all parties to set the baseline rate correctly.

Q. Please explain the bands beyond the first $25 million.

A. The second band, from $25 million to $120 million, is meant to capture a significant range of power cost risks reflected in PSE's electric portfolio, while preserving an upper range familiar to all parties. [redacted] By retaining 10% of the upside or downside of this second band, the Company will continue to have significant incentive to manage power costs and achieve power cost savings.

The final sharing band, for costs or savings plus or minus $120 million, with 95% customer sharing and 5% shareholder sharing, is meant to continue to provide protection to the Company in the current PCA Mechanism sharing bands from extreme negative departures from the power costs that are embedded in rates, as well as to continue to provide a small upside incentive in the event such significant power cost savings could be achieved. [redacted].

V. CONCLUSION

Q. Please summarize your testimony.

A. The Company's modeling of power cost risks associated with its electric portfolio shows that actual power costs are likely to vary substantially from year to year above or below the power cost baseline that is embedded in rates based on projections of future conditions that cannot be known at the time rates are set. The availability of water for hydro generation is a driver of such risk that cannot be effectively hedged. Even if hydro conditions could be perfectly forecast or hedged, volatility would remain in PSE's power costs due to factors such as weather and natural gas price variability.

Given the results of the Company's modeling and the expiration of the $40 million cap in the Company's PCA Mechanism as of June 30, 2006, PSE is proposing to revise the current PCA Mechanism sharing bands. PSE's proposed revised sharing bands would reflect a sharing of power cost risks as between the Company's customers and its shareholders that is more equitable than the current sharing bands, and that would continue to incent the Company to aggressively manage power costs.

Q. Does that conclude your testimony?

A. Yes, it does.

[BA060420025]