Exhibit No. __ TC (JOINT-8TC)
Docket Nos. UE-060266/UG-060267
Witnesses: Yohannes Mariam
Jim Lazar
Donald Schoenbeck
REDACTED VERSION

BEFORE THE WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	DOCKET NO. UE-060266 DOCKET NO. UG-060267 *(Consolidated)*

DIRECT TESTIMONY OF

YOHANNES MARIAM
JIM LAZAR
DONALD SCHOENBECK

ON BEHALF OF

STAFF OF THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION
PUBLIC COUNSEL
THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

POWER COST ADJUSTMENTS

CONFIDENTIAL PER PROTECTIVE ORDER

July 25, 2006

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I. INTRODUCTION

Qualifications of Jim Lazar

Q. Please state your name and the party for whom you are appearing.

A. My name is Jim Lazar and I am appearing on behalf of Public Counsel. My business address is 1063 Capital Way S. #202, Olympia, WA. My qualifications are included in Exhibit No. __ (Joint-2) to my joint testimony on natural gas rate spread, rate design and low income bill assistance.

Qualifications of Donald Schoenbeck.

Q. Please state your name and the party for whom you are appearing.

A. My name is Donald Schoenbeck and I am appearing on behalf of the Industrial Customers of Northwest Utilities (ICNU), a non-profit trade association, whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Puget Sound Energy, Inc. My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660. My qualifications are included in Exhibit No. __ (Joint-3) to my joint testimony on natural gas rate spread, rate design and low income bill assistance.

Qualifications of Yohannes Mariam

Q. Please state your name and the party for whom you are appearing.

A. My name is Yohannes KG Mariam and I am appearing on behalf of the Staff of the Washington Utilities and Transportation Commission. My business address is 1300 S. Evergreen Park Drive S.W., P.O. Box 47250, Olympia, WA 98504. My qualifications are included in my response testimony on weather normalization, Exhibit No. __ (YKGM-1T).

II. SCOPE AND SUMMARY OF JOINT TESTIMONY

Q. What is the purpose of your joint testimony?

A. The purpose of this testimony is to provide the recommendation of Staff, Public Counsel and ICNU (collectively referred to as the "Joint Parties") on the proposed power costs Puget Sound Energy, Inc. ("PSE", "Puget" or "the Company") is seeking to recover in this docket.

Q. Please briefly summarize your testimony.

A. The update PSE filed in this general rate case docket on July 7, 2006 ("Update") contains a power cost projection of $968.4 million for the 2007 test period. This is a power cost increase of $93.4 million as compared to the 2005 PCORC application (Docket No. UE-050870), which utilized a test period of December 2005 through November 2006. As compared to the power cost just approved by the Commission in July, the Update represents a revenue increase associated with power costs--including the acquisition of the Wild Horse facility—of almost $51 million. This is a substantial amount since the entire Update electric revenue deficiency is only $43 million.

The Joint Parties' recommendations reduce the level of PSE's power costs by $21.6 million. This translates into a $22.3 million reduction in revenue requirement after taking into account the production factor adjustment and revenue sensitive taxes. The recommendations are based upon a review of the AURORA modeling PSE has performed for this proceeding. This review has found major deficiencies in the input data and resulting AURORA derived hourly prices. These prices are a critical output since PSE assumes it will procure a large quantity of its energy needs based upon these hourly values. Correcting some of these data set deficiencies reduces PSE's AURORA power cost estimate by about $11.7 million. After taking into account certain fixed price contracts, the net adjustment is a power cost reduction of $9.9 million.

In addition, the Joint Parties have concluded the AURORA derived hourly prices should not be used to value the open market purchases in this proceeding. In place of the AURORA derived hourly prices, the Joint Parties recommend the Commission use monthly on-peak and off-peak forward electricity prices for the Mid-Columbia market hub to value PSE's short term power costs. The prices should be derived from a three month average as is currently done for gas costs. There are several reasons why this recommendation should be adopted by the Commission. First, the forward prices provide an unbiased estimate of future electricity prices at a very robust market trading center. The forward market prices reflect real world opportunities and are an unbiased yardstick for determining PSE's purchase power costs. Second, use of monthly on-peak and off-peak forward prices closely tracks how PSE actually procures most of its power in the market. PSE simply does not rely on an hourly market for the vast majority of its short term needs as is implied by using the hourly AURORA derived prices. Third, it is consistent with the manner in which gas costs are determined. Both commodities are linked within the real market place and both should be linked in PSE's power cost determination. Finally, adoption of this recommendation would lessen the need to scrutinize the very large AURORA data set for faulty specifications within the entire western United States, Canada and Mexico, an extraordinarily time intensive task. Applied to the Joint Parties AURORA results and fixed price contracts, the forward price adjustment is an incremental reduction of $11.7 million.

Taken together, the Joint Parties recommendations addressing AURORA modeling and market prices reduce PSE's proposed power costs by $21.6 ($9.9 + $11.7) million.

The last issue the Joint Parties address is PSE's peaking capacity cost calculation. PSE has included $1.1 million in the test year power cost projection to cover a capacity shortfall for December 2007. The capacity shortfall is based on an extreme peak design temperature of 12 degrees. The Joint Parties recommend that in future proceedings, the peak temperature be based on the historical temperatures experienced over the same time period used for weather normalization.

III. BACKGROUND AND SUMMARY OF PUGET'S REQUEST

Q. Please explain the basis for the Company's application in this proceeding.

A. PSE filed its application pursuant to a multiparty settlement that was adopted by the Commission in Docket No. UE-050870. The settlement called for PSE to make two filings. The first filing was to update the base power cost for the period of July 1, 2006 through December 31, 2006. PSE's filing sought a power cost increase of $45.4 million for this six month period. On an annual basis, this represents an increase in power costs of over $94 million (there are slightly higher sales in the January – June period). The filing was accepted by the Commission in a consolidated order in Docket Nos. UE-050870 and UE-060783. PSE's application in this docket is the second filing required under the settlement. Pursuant to the agreement, PSE was required to file a general rate case so that a revised power cost would be put into place for 2007.

Q. Why did the Joint Parties want this second filing?

A. The Joint Parties believed the second filing was critical for at least two reasons. First, the settlement called for shifting the power cost adjustment mechanism to a calendar year basis (January through December) rather than the current July through June period. Since the July – December 2006 update filing was not based on a full 12 month period, it was felt that a filing reflecting 2007 power costs was needed to properly set the 2007 base power cost level. The second reason for requiring the 2007 test year filing was a belief—really a hope—that market prices could trend downward in 2007 if not sooner. Under this circumstance, PSE could potentially over collect its power cost if the base power rate were in place beyond the six month test period ending December 2006.

Q. Have market prices declined since the settlement was approved by the Commission in Docket No. UE-050870?

A. Yes, particularly in the on-peak period where PSE has the greatest need for power. The decline in market prices is readily apparent by comparing the price of the power

PSE has procured for the July through December 2006 as reflected in the Docket No. UE-060783 update filing with the average of more current forward market prices for the same period. This on-peak price comparison is set forth in the following table.

PSE On-Peak Purchases to Current Market Prices

[redacted]

The market prices reflected in the above table are the average from the last three months of forward prices for the three month period ending on May 23, 2006 as provided by Kiodex, the service used by PSE. The difference in cost between the prices paid by PSE for the power--and reflected in the filing-- and more recent prices is [redacted] over just the six month period. On an annual basis, this is equivalent to about [redacted].

Q. **Have you prepared a similar table with the off-peak prices?**

A. Yes. The next table does the same comparison for the off-peak period. The table indicates that while there are rather large differences for certain months, for the six month period, the market prices are only [redacted] less than the price PSE paid to procure the power, equivalent to [redacted] for the year.

PSE Off-Peak Purchases to Current Market Prices

[redacted]

When combined, the above tables show PSE's current base purchase power cost— approved in July-- is almost [redacted] greater than current forward prices.

Q. Are the Joint Parties concerned about the prices PSE has paid for this power?

A. Yes. At the appropriate time all parties will need to review and thoroughly examine the evidence PSE has to support the prices paid for the power and the volume of power that was procured. For now though, this comparison is provided simply to show the decline in forward market prices that should be factored into the power cost determination in this proceeding.

Q. Does PSE's update filing contain a proposed increase in power costs beyond what the Commission approved in the July PCORC update filing?

A. Yes. The Update filing contains a proposed power cost of $968.4 million as set forth in the testimony of Mr. Mills. This value is composed of fixed and variable related operations and maintenance expenses, including transmission related costs. In addition, PSE is seeking the inclusion of the Wild Horse wind project in this application, which will increase PSE's generation-related rate base and depreciation expense. As noted in the Update testimony of Mr. Story, the proposed power cost Baseline Rate is $59.331/MWh as compared to the July PCORC rate of $56.901/MWh, an increase of 4.2%. Thus, just the power related costs represent a revenue requirement increase of about $51 million in an application where PSE is seeking only $43 million.

IV. JOINT PARTIES AURORA DATA RECOMMENDATIONS

Q. Have you analyzed PSE's power cost projections in this application?

A. Yes. We have reviewed the original and Update filings with regard to PSE's power cost projection for 2007. A substantial portion of PSE's projected power costs is a result of the AURORA modeling effort. The AURORA model is a fundamentals model that produces hourly spot electricity prices at user defined market hubs or areas based upon the loads, resources, transmission availability and gas costs PSE has included in its AURORA input data files. The model produces an hourly economic dispatch for all resources within the Western Electricity Coordinating Council (WECC) which covers the western United States and portions of Canada and Mexico.

The AURORA input data files require an accurate assessment of all electricity demands and each available resource within an enormous geographical area. It should come as no surprise that the necessary input data consists of thousands of lines—each with numerous columns—of specific data required for a simulation.

PSE uses the AURORA derived hourly values to price its projected market purchases. The Power Cost Adjustment mechanism is then used retrospectively to take actual costs into account.

In the Update filing, the market purchase power cost is $289 million out of $707 million of variable related power costs produced from the AURORA simulation. The AURORA derived spot prices represent 29% of the variable costs output from the AURORA modeling effort, a very substantial amount.

Q. Do you agree with PSE's AURORA update input data set specifications?

A. No. There are several data specification areas that are wrong which result in an overstatement of the hourly spot prices derived by AURORA. This in turn results in too high of a power cost projection by PSE for 2007. These areas are:

- Excluding and/or under rating the output of major generation facilities;
- Mis-specifying certain operating parameters for gas-fired combustion turbine generating units; and
- Improper hydro shaping factors.

While we have not undertaken the labor intensive effort to review each and every resource line (and column) of PSE's AURORA data set, we have found by correcting just a limited number of resources with these problems, PSE's AURORA power cost is overstated by at least $11.7 million.

A. Additional Generation

Q. Please describe your findings with regard to generation capacity ratings.

A. Early on in the process of reviewing PSE's initial filing, we noted the AURORA data file substantially understated or omitted a number of large generating units in the western United States. At that time, we believed the understatement was at least 6,500 MW of generating capacity. In the Update filing, PSE has included a large portion but not all of this missing capacity.

Exhibit No. __ (Joint-9C) is a comparison of the capacity rating employed by PSE in the AURORA input file with the actual availability from these units. For the limited review we undertook—which focused on utility owned or contracted additions and cogeneration facilities in Western states--PSE's Update data set is still short by over [redacted] of capacity.

PSE's Update missed two utility contracted/owned additions of PacifiCorp—the Currant Creek steam generators completed in April of this year and the Lakeside plant scheduled for completion by July, 2007. The remaining "missing" capacity is a result of not correctly specifying the net output of cogeneration facilities located in California and Nevada. The net output of these facilities is the amount of power sold after fulfilling any on-site or local need.

While all of these cogeneration resources supply power that must be taken by the purchasing utility (reducing that utility's dependence on market purchases), there is one recent exception for the Kern River Cogeneration facility. The initial 20 year contract for the sale of the output from this facility (4-75 MW combustion turbines) to Southern California Edison (SCE) was scheduled to terminate in August 2005. Pursuant to an amendment recently approved by the California Public Utilities Commission, only two of the 75 MW units will be running in a base load manner to supply steam for the recovery of heavy oil. The remaining two 75 MW units will be on call to SCE for providing peaking needs. Thus, for AURORA modeling, this facility should be split into two plants with the peaking units having an associated heat rate of 12,500 BTUs/kWh, while the other two units should reflect a heat rate comparable to that of other cogeneration facilities.

Q. Have you performed an AURORA sensitivity incorporating your additions into PSE's data set?

A. Yes. Adding this limited amount of additional capacity—physically located well outside PSE's service territory--into the AURORA data file reduced PSE's AURORA produced power cost by $3.5 million for 2007. This was based on comparing two single average water year (as opposed to 50 water year) simulations. This shows how a small number of poor or erroneous AURORA input specifications—even for units very remote to PSE's service territory—have a direct impact on the hourly spot prices calculated by the AURORA model and used in PSE's power cost projection.

Q. Do you believe you have corrected for all the capacity that was missing from the data set?

A. It is extremely unlikely that we have identified and included all missing WECC capacity in the data file. For the most part, our review was very specific to generating additions we were aware were being added and for major (about 10 MW or greater) cogeneration facilities known to have been providing reliable power for many years.

Undoubtedly, there are further corrections and updates required to the enormous PSE resource data file.

B. Minimum On and Off Times

Q. What resource specific information is required for AURORA to perform its economic dispatch?

A. For each resource the user needs to specify numerous parameters including: location, heat rate, fuel cost, capacity, variable operation and maintenance expense, maintenance rate, whether it is a must-run or cycling resource, minimum run capacity value, heat rate at the minimum level, a minimum up time, minimum down time, start up costs and ramp rate.

Q. Have you reviewed and validated PSE's specifications for all resources in the data base?

A. No, that would be an enormous task. We have however, reviewed the specifications for most of the new large combined cycle combustion turbines (CCCTs) that have been added in recent years within the WECC.

Q. What has this review revealed?

A. PSE has not used a reasonable value for two of the operating parameters for these types of facilities. The parameters are the minimum up time and the minimum down time. The user specifies the minimum required hours of operation for a resource in the minimum up time value. The minimum down time is the required number of hours a unit or facility must be "off line" or not used in the economic simulation. A resource will only be dispatched to serve load if it is economic for it to run over the entire minimum up time specified by the user. Similarly, a resource must be off-line once it is "shut down" the minimum off hours and therefore is not available in the economic dispatch during this period.

Q. Please give an example of how the specification of these values could impact AURORA's economic dispatch.

A. Assume there is a large and sharp peak load condition occurring for a period of six hours similar to SCE's summer peak period. AURORA will attempt to meet this load with the most economic resource available to the model. In this era, the resources could very well be either a simple cycle combustion turbine (CT) with an associated heat rate of 10,000 BTU/kWh or a combined cycle combustion turbine (CCCT) with a 7,000 BTU/kWh heat rate. Assuming similar start-up costs, the economic resource of choice would be the CCCT due to its lower heat rate. However, AURORA could only select this resource if the minimum on time was six hours or less. If the minimum on time was greater than 6 hours, the resource could not be considered by AURORA. In this latter instance, AURORA would select the lower-efficiency CT to satisfy a portion of the peak period load thereby resulting in a higher cost for these hours. We realize this is a very simplistic example and in reality, there would be a host of other considerations. However, the fundamental issue is valid. Resource availability within AURORA can be restricted by selection of these minimum on and off specifications.

Q. What values did PSE use for these parameters?

A. For some CCCTs PSE has used a minimum up time of [redacted] hours coupled with a minimum off time of [redacted] hours. For other identical facilities, PSE has used a minimum up time of [redacted] hours with a minimum down time of [redacted] hours. Exhibit No. __ (Joint-10C) shows the parameters used by PSE for a sample of these facilities. Note however, that even this partial listing totals over 23,000 MWs of capacity.

Q. Are these values representative of how these units can be operated?

A. No. The values for the minimum on and off times should reflect how these facilities can be operated. One reason utilities and independent power producers have selected natural gas CT or CCCT units is due to the operating flexibility they provide. Generally, these facilities can be started very quickly even if the machine had not operated for several days. The units can achieve required dispatch levels sooner if the unit had been operated within the last 24 hours, and almost instantly if the unit had merely been ramped down overnight in anticipation of higher demands the next day. PSE's parameters simply do not allow this to occur within the model, even though it may commonly occur in the real world.

There are several contracts in the public domain that specify operating parameters for combined cycle plants. One example is the contract SCE has executed with a wholly owned subsidiary for the 1,000 MW Mountainview plant (2-500 MW CCCT units). This contract requires that any dispatch "shall be for a run time of no less than three (3) consecutive hours per Unit and a down time of no less than three

(3) consecutive hours per Unit." Further, the agreement specifies that if the unit(s) had been off, the start-up lead time is dependent upon the number of hours the unit(s) had been off line. The following table shows the specific lead time for the various periods the unit(s) had been off line.

	Range	Start Time
Cold Start	Off > 48 hours	6 hours
Warm Start	Off 8 – 48 hours	3 hours
Hot Start	Off < 8 hours	2 hours

The Mountainview contract calls for a minimum up time of 3 hours and a minimum off time of 6 hours—if the plant had not operated in 48 hours. These values are much less restrictive than the minimum on and off times PSE modeled for these facilities.

Q. What impact would using lower minimum on and off times have on PSE's power cost projection?

A. Easing the operating constraints of these units should result in a more economical dispatch of the power system and therefore a lower projected power cost from the Aurora model for PSE.

Q. What values should be used for these types of generating units?

A. The values for the minimum on and off times should reflect how these facilities can be operated, but the user must also take into account the available options offered in the AURORA data set. The Joint Parties recommend the Commission require the use of a minimum on time of [redacted] hours and a minimum off time of [redacted] hours. The values come from the contract between the California Department of Water Resources and the Sunrise Power Company. The values are slightly more restrictive than the SCE Mountainview agreement, but within the mid-range of contractual obligations for combustion turbines. Use of these values will allow for adequate cycling of the facilities within a 24 hour period.

Q. Have you performed an aurora sensitivity using these parameters?

A. Yes. For the facilities listed in Exhibit No. __ (Joint-10C), we have altered PSE's minimum values to our recommended hours. It resulted in lowering PSE's projected power cost by $2.4 million based upon a comparison of two single average water year AURORA runs. This shows--once again--how sensitive PSE's power cost projection is to the input data specifications employed by the modeler.

C. Hydro Generation

Q. How has PSE determined the available hydro generation?

A. PSE's AURORA modeling and power cost result is based upon 50 water years (1929 through 1978).

Q. Do you have any concerns with PSE's hydro modeling?

A. Yes. The monthly shaping factors used by PSE in the AURORA modeling do not produce reasonable on-peak and off-peak generation amounts. Simply put, the AURORA modeled result does not reflect as much shaping of hydro generation into the more valuable on-peak period as the operators of hydro projects actually achieve. The following two tables compare the expected generation for the on and off peak period by month between PSE's April 14, 2006 "position and exposure" report and PSE's AURORA modeling. The report was provided in response to a data request (ICNU 5.140) and has been included as Exhibit No. __ (Joint-11C). Each month of the on-peak table shows a very consistent result. The AURORA modeling has understated the expected on-peak hydro generation levels. Similarly, the off-peak table shows too much generation produced by the AURORA modeling effort for all months.

On-Peak Hydro Generation Comparison (AMW)

	PSE Risk Assessment	PSE AURORA	Delta
Jan-07	[redacted]	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]	[redacted]
May-07	[redacted]	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]	[redacted]
Nov-07	[redacted]	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]

Off-Peak Hydro Generation Comparison (AMW)

	PSE Risk Assessment	PSE AURORA	Delta
Jan-07	[redacted]	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]	[redacted]
May-07	[redacted]	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]	[redacted]

Nov-07	[redacted]	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]

Q. Can the AURORA user impact the amount of hydro generation between on-peak and off-peak periods?

A. Yes. The AURORA modeler can specify shaping factors to shift expected monthly generation between on and off peak periods. PSE has used the same value in each and every month. The following table compares the PSE AURORA result as a percentage of the average generation for the month. On average, the off-peak generation level was only [redacted] of the average monthly generation and the on-peak generation was only [redacted] of the average monthly level.

PSE AURORA Shape
Hydro as Percent of Average

	Off-Peak	On-Peak
Jan-07	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]
May-07	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]
Nov-07	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]
Average:	[redacted]	[redacted]

The next table presents the same comparison using the April risk assessment. This table shows PSE is expecting on average to get [redacted] less energy from its hydro resources during the off-peak hours and [redacted] more energy from hydro during the more valuable on-peak hours, compared with the AURORA result.

PSE Risk Shape
Hydro as Percent of Average

	Off-Peak	On-Peak
Jan-07	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]
May-07	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]
Nov-07	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]
Average:	[redacted]	[redacted]

Q. Have you determined more appropriate shaping factors?

A. Yes, to a certain extent. Through an iterative process of running a single average water year, we determined a series of factors to more closely match the energy differentiation contained in the risk report, but for the same amount of hydro generation produced by the AURORA data set. The following tables present the results of this effort based upon running the factors through all 50 water years with PSE's modeling effort.

The on-peak comparison shows the Joint Parties shaping factors resulted in [redacted] AMW of additional generation during the on-peak period with a corresponding reduction of [redacted] AMW during the off-peak period. It is important to state that under both the PSE AURORA result and the Joint Parties AURORA result, the same amount of total hydro generation is realized and it is within just 2 or 3 AMW of the PSE risk hydro generation.

On-Peak Hydro Generation – AMW

	PSE AURORA	Joint Parties	PSE Risk
Jan-07	[redacted]	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]	[redacted]
May-07	[redacted]	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]	[redacted]
Nov-07	[redacted]	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]
Difference:		[redacted]	[redacted]

Off-Peak Hydro Generation – AMW

	PSE AURORA	Joint Parties	PSE Risk
Jan-07	[redacted]	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]	[redacted]
May-07	[redacted]	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]	[redacted]
Nov-07	[redacted]	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]
Difference:		[redacted]	[redacted]

Q. Why should the Commission adopt your shaping factors as compared to the PSE values?

A. Ideally, the correct shaping factors would have resulted in the hydro generation production levels contained within PSE's risk assessment report since it is these values that determine PSE's short term procurement needs and purchasing strategies.

The Joint Parties factors result in on and off peak generation levels much closer to these risk assessment values than PSE's AURORA modeling effort. Accordingly, these values should be adopted by the Commission.

Q. How did this shift in hydro generation affect the projected power cost?

A. Our hydro shaping factors reduced the AURORA power cost projection by an additional $6.0 million based upon a single average water run. This is an incremental amount in addition to our previous adjustments related to additional capacity and minimum operating parameters.

Q. Have you performed an AURORA simulation correcting all the data errors you have identified?

A. Yes. Exhibit No. __ (Joint-12) summarizes the result of our recommended 50 water year AURORA simulation along with PSE's Update. Our simulation results in less reliance on PSE's gas-fired generating resources and more use of lower-cost market purchases. The AURORA-related costs are decreased by $11.7 million as compared to PSE's simulation.

Q. Please explain the difference in the "Other" column under the market purchase row (line 15) of Exhibit No. ___ (Joint-12).

A. The amount in the "Other" column is a post AURORA processing adjustment that takes into account the fixed price contracts PSE has executed for the rate year. The adjustment compares the actual costs of these contracts to the AURORA generated costs for the amount of power. In PSE's Update filing, the adjustment is a credit of $2.9 million since the actual cost of these agreements is less than the AURORA generated cost. In our recommended simulation, the AURORA generated costs are closer to the actual prices paid for this power. Consequently, our post processing adjustment is a credit of only $1.1 million. This calculation is presented in Exhibit No. __ (Joint-13C). In total, the Joint Parties AURORA data recommendations reduce PSE's power cost by $9.9 million as shown by Exhibit No. __ (Joint-12).

V. FORWARD MARKET PRICE RECOMMENDATION

Q. Do PSE's AURORA derived hourly prices result in power costs comparable to forward market prices?

A. No. The following table compares the AURORA produced costs for PSE's market purchases with the comparable forward market prices—supplied by PSE's vendor--for the three months ending November 30, 2005 for PSE's initial filing.

PSE AURORA Versus Forward Prices - Initial Filing

	On-Peak				Off-Peak		
	AURORA	Forwards	Difference		AURORA	Forwards	Difference
Jan-07	[redacted]	[redacted]	[redacted]	Jan-07	[redacted]	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]	[redacted]	Feb-07	[redacted]	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]	[redacted]	Mar-07	[redacted]	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]	[redacted]	Apr-07	[redacted]	[redacted]	[redacted]
May-07	[redacted]	[redacted]	[redacted]	May-07	[redacted]	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]	[redacted]	Jun-07	[redacted]	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]	[redacted]	Jul-07	[redacted]	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]	[redacted]	Aug-07	[redacted]	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]	[redacted]	Sep-07	[redacted]	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]	[redacted]	Oct-07	[redacted]	[redacted]	[redacted]
Nov-07	[redacted]	[redacted]	[redacted]	Nov-07	[redacted]	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]	[redacted]	Dec-07	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]	Average:	[redacted]	[redacted]	[redacted]

This table indicates very large disparities in monthly values for both on and off peak months. For the on-peak period---when PSE is most active in acquiring power, the AURORA derived costs are over [redacted]/MWh above the forward prices. The next table presents the same information for PSE's Update filing using forward prices for the three months ending May 23, 2006. The Update comparison now shows even larger disparities in the average prices produced for both the on-peak and off-peak period between PSE's AURORA modeling and the forward markets.

PSE AURORA Versus Forward Prices - Updated Filing

Update Filing Comparison On-Peak			
	AURORA	Forwards	Difference
Jan-07	[redacted]	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]	[redacted]
May-07	[redacted]	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]	[redacted]
Nov-07	[redacted]	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]

Update Filing Comparison Off-Peak			
	AURORA	Forwards	Difference
Jan-07	[redacted]	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]	[redacted]
May-07	[redacted]	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]	[redacted]
Nov-07	[redacted]	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]

A comparison of the average of the two tables shows the drop in forward market prices has simply not been reflected in PSE's AURORA Update modeling effort. In fact, for the off-peak period, the Update AURORA results are even higher than the initial filing.

Q. Have you prepared a similar table with the AURORA prices produced from your AURORA run?

A. Yes. The following table presents this comparison. While the Joint Parties results are closer to the forward prices than PSE's Update result (consistent with our inclusion of more complete information on power plant availability and operating limitations), the AURORA derived values are still too high when compared to the forward prices.

Joint Parties AURORA Versus Forward Prices

	On-Peak				Off-Peak		
	AURORA	Forwards	Difference		AURORA	Forwards	Difference
Jan-07	[redacted]	[redacted]	[redacted]	Jan-07	[redacted]	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]	[redacted]	Feb-07	[redacted]	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]	[redacted]	Mar-07	[redacted]	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]	[redacted]	Apr-07	[redacted]	[redacted]	[redacted]
May-07	[redacted]	[redacted]	[redacted]	May-07	[redacted]	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]	[redacted]	Jun-07	[redacted]	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]	[redacted]	Jul-07	[redacted]	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]	[redacted]	Aug-07	[redacted]	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]	[redacted]	Sep-07	[redacted]	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]	[redacted]	Oct-07	[redacted]	[redacted]	[redacted]
Nov-07	[redacted]	[redacted]	[redacted]	Nov-07	[redacted]	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]	[redacted]	Dec-07	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]	Average:	[redacted]	[redacted]	[redacted]

Q. Why do you believe the results produced by AURORA are not matching forward market prices?

A. The AURORA derived prices are expected market clearing prices given assumed supply and demand for electricity. It assumes a hypothetically ideal situation and wouldn't fully take into account the impact of decisions made by market participants, marketers, generators, and utilities. Some of these decisions may deviate significantly from the assumptions that are input to the model. The difference could also be due to factors such as including erroneous data specifications and necessary modeling simplifications. However, the forward market prices are real prices that real utilities can purchase real energy at, while the AURORA results are outputs of a computer model of an efficiently functioning market.

Q. Are you recommending that the AURORA derived hourly prices be used to calculate PSE's market purchase costs?

A. No. Instead of using the AURORA derived hourly prices to determine the purchase power cost, the Joint Parties recommend using monthly on-peak and off-peak forward market prices at the Mid-Columbia (Mid-C) market hub to value the power.

Q. Why?

A. There are several reasons why this recommendation should be adopted by the Commission. First, the forward prices provide an unbiased estimate of future electricity prices at a very robust market trading center. Second, use of monthly on-peak and off-peak forward prices most closely tracks how PSE actually procures most of its power in the market. Third, it is consistent with the manner in which gas costs are determined. Finally, adoption of this recommendation would lessen the need to scrutinize the very large AURORA data set for faulty specifications within the entire western United States, Canada and Mexico, an extraordinarily time intensive task.

A. Forward Markets Are Robust

Q. Please elaborate on your view of forward prices providing an unbiased estimate of expected power costs.

A. As electricity markets have evolved in recent years there are far more purchasers and sellers of power. With the presence of these numerous marketers, brokers and independent generators, forward electricity markets are more robust. As an example, the following tables show the day-ahead activity in MWhs and deals for several recent trading days as reported by Platts Energy Trader for western U.S. markets.

Volumes in MWH for Various Trading Hubs from Platts Energy Trader
On Peak

	6/23/2006	6/26/2006	6/27/2006	6/29/2006	6/30/2006
COB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mid Columbia	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Palo Verde	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mead	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Four Corners	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NP15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SP15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Volumes in MWH for Various Trading Hubs from Platts Energy Trader
Off Peak

	6/23/2006	6/26/2006	6/27/2006	6/29/2006	6/30/2006
COB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mid Columbia	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Palo Verde	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mead	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Four Corners	[redacted]	[redacted]		[redacted]	[redacted]
NP15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SP15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Number of Deals for Various Trading Hubs from Platts Energy Trader On Peak					
	6/23/2006	6/26/2006	6/27/2006	6/29/2006	6/30/2006
COB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mid Columbia	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Palo Verde	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mead	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Four Corners	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NP15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SP15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Number of Deals for Various Trading Hubs from Platts Energy Trader Off Peak					
	6/23/2006	6/26/2006	6/27/2006	6/29/2006	6/30/2006
COB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mid Columbia	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Palo Verde	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mead	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Four Corners	[redacted]	[redacted]		[redacted]	[redacted]
NP15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SP15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

As is readily apparent from this data, the Mid-C trading hub is always one of the top market hubs within the WECC. While the above illustration is for the day-ahead market, for the four major WECC trading hubs of Mid-C (for the Pacific Northwest), Palo Verde (near the Southern California border), NP-15 (Northern California) and SP-15 (Southern California), forward prices can be obtained through the year 2010.

For an example of the robustness of the Mid-C market that directly involves PSE, consider the number of counter parties PSE has executed short-term power arrangements for 2006. In response to a data request (ICNU 5.138) PSE provided a listing of all short-term power purchased for 2006 as of June 28, 2006. A portion of this response is attached as Exhibit No. __ (Joint-14C). This response shows that PSE has entered into agreements with 33 suppliers as listed in the following table.

Counter Parties For 2006 Short Term Purchases
As of June 28, 2006

1 [redacted]
2 [redacted]
3 [redacted]
4 [redacted]
5 [redacted]
6 [redacted]
7 [redacted]
8 [redacted]
9 [redacted]
10 [redacted]
11 [redacted]
12 [redacted]
13 [redacted]
14 [redacted]
15 [redacted]
16 [redacted]
17 [redacted]
18 [redacted]
19 [redacted]
20 [redacted]
21 [redacted]
22 [redacted]
23 [redacted]
24 [redacted]
25 [redacted]
26 [redacted]
27 [redacted]
28 [redacted]
29 [redacted]
30 [redacted]
31 [redacted]
32 [redacted]
33 [redacted]

The data response also indicates that PSE procures most of its power at the Mid-C market hub. In fact, 267 out of the 283 transactions specify a Mid-C delivery point.

The Mid-C forward prices reflect real market transactions at a very competitive market hub. Therefore, these real world prices are an objective and unbiased value that can be used as a benchmark for the expected prices PSE will pay for power in the near term. This fact is borne out by PSE's forward market purchase activity for the rate year. The following table compares the actual forward purchase price PSE has executed for the rate year with the AURORA Update cost and recent forward market prices. The forward market prices used in the table are from Kiodex—PSE's vendor—and reflect a three month average ending May 23, 2006.

On-Peak Purchase Comparison

	PSE	AURORA	Kiodex	Difference from	
	Purchases	Update	Forwards	AURORA	Forwards
Jan-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jul-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aug-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sep-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Oct-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nov-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dec-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Off-Peak Purchase Comparison

	PSE	AURORA	Kiodex	Difference from	
	Purchases	Update	Forwards	AURORA	Forwards
Jan-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Feb-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mar-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Apr-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jun-07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For each table, use of the forward market prices is a superior indicator of the actual costs PSE has incurred for this power rather than the AURORA derived costs. For this reason, forward prices should be used instead of AURORA derived values for calculating PSE's power cost in this proceeding.

B. PSE's Power Procurement

Q. Please explain your understanding of how PSE procures its short term energy needs.

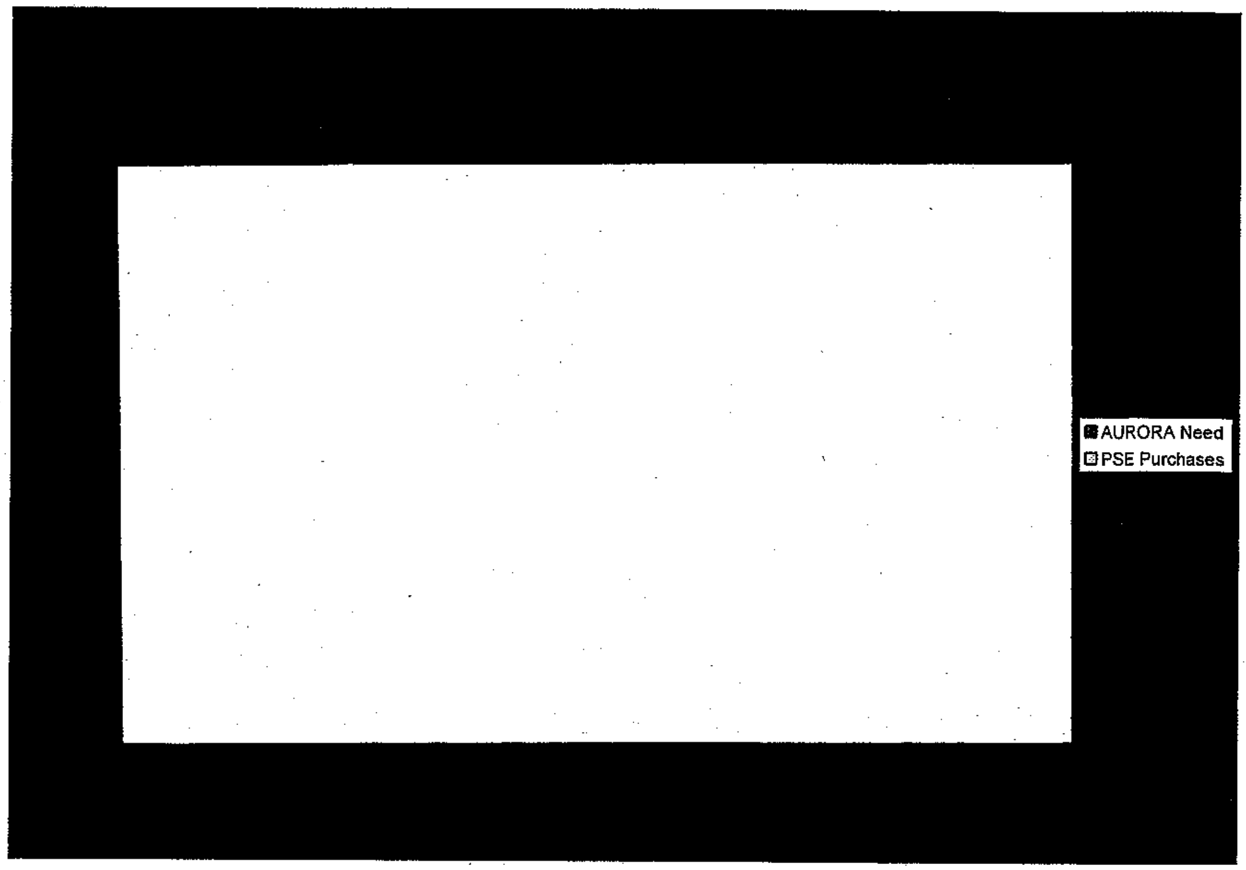
A. PSE's decision to procure power in the short and near term is driven by price, need and the financial ability to execute transactions. By monitoring forward prices and through position reports indicating available resources and demand, PSE enters into transactions covering either the on-peak or off-peak period and occasionally PSE purchases an "all hour" block. The "Hours ID" column of Exhibit No. __ (Joint-14C) identifies the associated purchase as an on-peak block (ID 1), an off-peak block (ID 2) or an all hour purchase (ID 3). PSE will procure the power in the forward market as it gets closer to the time the power is needed. Most critically, the exhibit shows the substantial amount of power PSE procures in the forward market. The duration period of each transaction is usually for a month or quarter as can be gleamed from an examination of the PSE data response. Exhibit No. __ (Joint-15C) presents an analysis undertaken by the Joint Parties to understand the forward nature of PSE's procurement activity. This exhibit is based on all but one transaction from the PSE data response. (It excludes one transaction that covered a two year purchase.) The last two columns of this exhibit contain critical information for understanding PSE's procurement practice. The first of these columns entitled "Trade Date to Start" indicates the number of days from when a deal was executed to its corresponding start date. In most instances, it is a long period of time with an average value of [redacted] days—almost [redacted]-- for these 282 trades. The last column on this exhibit presents the duration of each trade from the start date to the end date. The exhibit shows PSE's block purchases are most often for 30 or 90 day periods with a sample average [redacted] days.

Q. Is PSE's procurement strategy reflected in its AURORA modeling?

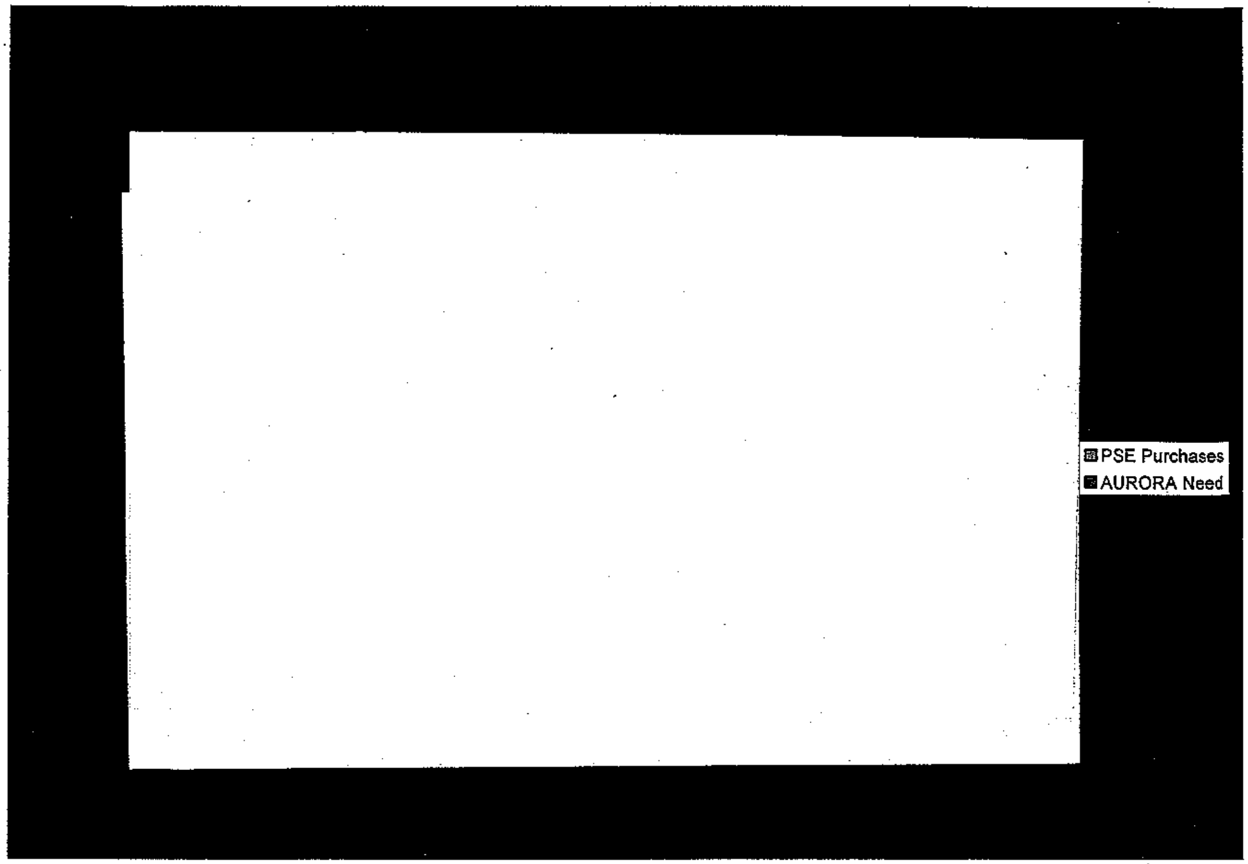
A. No. PSE's AURORA modeling assumes 100% of the hourly need is procured in the spot market. In actuality, PSE only needs to procure a much more limited amount in the daily and real time markets since it has procured substantial amounts of power in the forward market. Having already done this, PSE can use the hourly flexibility of its Mid-C resources to satisfy a good portion of the daily and real time needs. PSE simply does not purchase 100% of it needs in the hourly spot market, as is modeled in AURORA.

Q. Does PSE's procurement strategy impact PSE's power costs in rate proceedings?

A. It can depending upon the timing of the filing. The following chart is a comparison of amount of power PSE had purchased in the forward market versus the AURORA generated need at the time of PSE's rate filing in Docket No. UE-050870. Only a modest amount of power had been purchased since it was well ahead of when the power was needed. In fact, for the second half of the year, no short-term forward power had been procured.



The next chart is a comparison of the short-term power PSE has procured for the second half of 2006 (as of the time of the filing's preparation) versus the AURORA generated need from the recent PCORC Update filing. The chart shows that by the time this filing had been compiled, PSE had locked in a very substantial amount of power in the forward market for this near term need.



As we discussed earlier in the testimony, PSE will reflect the actual cost of the short-term purchases it has executed in its power cost determination. Therefore, PSE's initial filing in a general rate case will only reflect very modest purchase quantities. Then, when the filing is updated, a much larger amount of forward purchases will be reflected. With these updates, PSE's forward purchase costs—based upon forward purchase prices-- become much more relevant than the AURORA produced prices since the forward costs "trump" or replace the AURORA derived hourly prices.

After the fact, the actual expenditures for power purchases will be flowed through the PCA mechanism. Because the deviations from the levels set in the rate case are shared between consumers and the Company, it is critical that the most accurate and recent data be used in the rate case. The use of forward market data satisfies this need, while the use of AURORA data does not.

Q. Why does the PCORC update chart indicate purchases in excess of PSE's need?

A. It is not clear to the Joint Parties at this time why this substantial amount of power was procured. At the appropriate time, all parties will be given the opportunity to investigate the reasoning behind these purchases. The illustration is given as an example of how PSE's procurement strategy fills "the gap" with purchases in the forward market as it gets closer to the time when the power is needed. Very little is left to the "last minute."

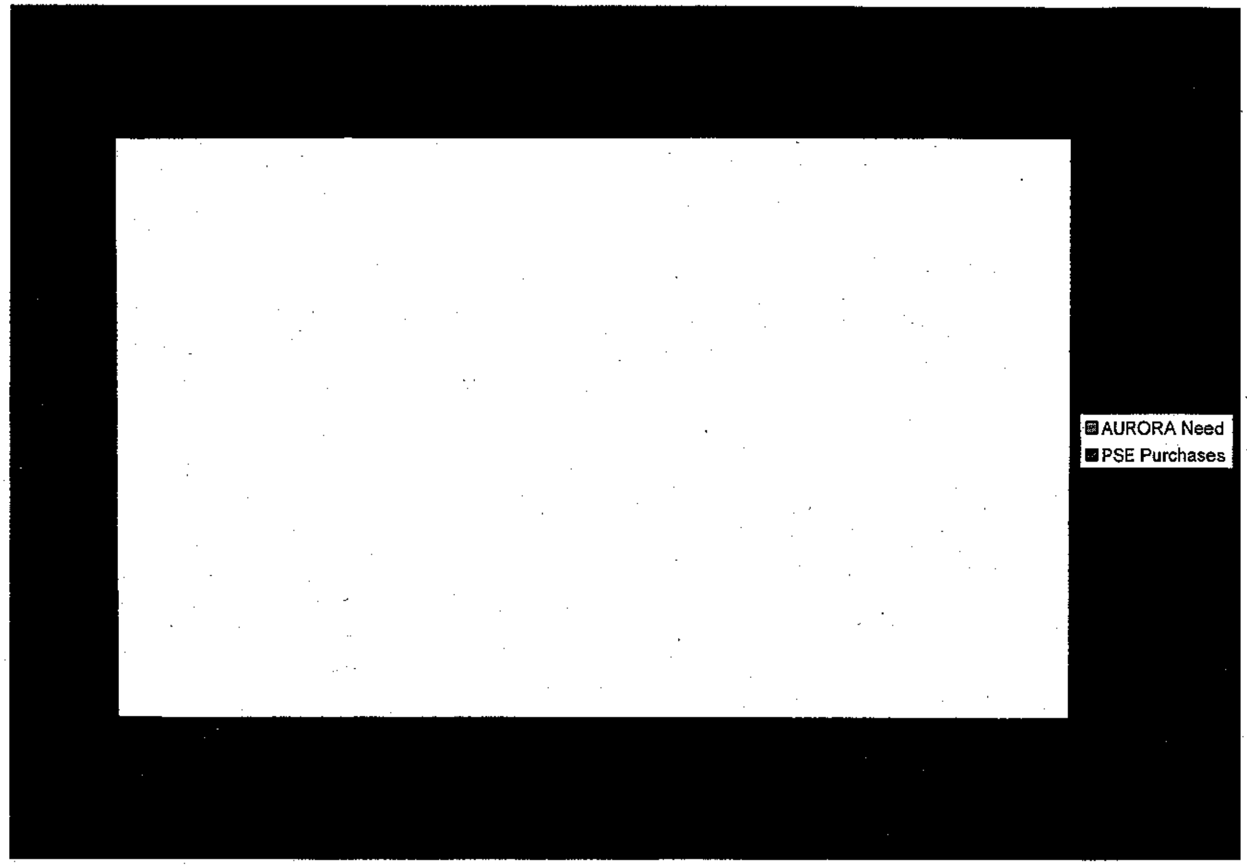
Q. Is this purchase strategy impacting the power costs in this docket?

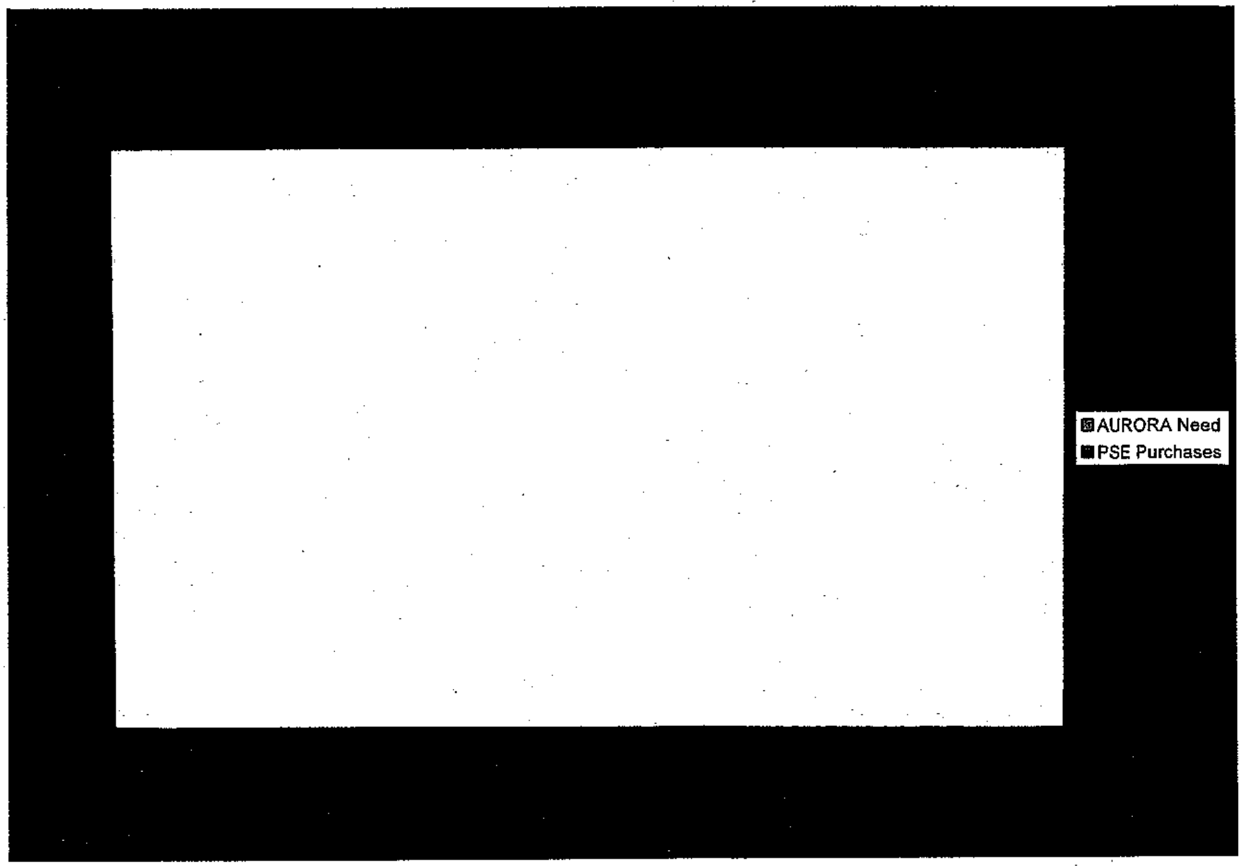
A. Yes, but only slightly. At the time PSE compiled its initial filing, it had only procured a modest amount of on-peak power in the forward market as is shown by the following chart. No off-peak forward purchases had been completed by the time the initial filing was compiled.

[redacted]

AURORA Need
PSE Purchases

By the time PSE had compiled its Update in this docket, a considerable amount of additional forward purchases had occurred. However, as shown by the next two charts the forward purchases fall far short of the block purchases that will ultimately be acquired by PSE for the rate period.


AURORA Need
PSE Purchases



As shown by these charts and Exhibit Nos. ___ (Joint-14C) and (Joint-15C), PSE's procurement practice is to buy much of its short-term needs through monthly block purchases in the forward market at the Mid-C delivery point. For this reason, the projection of PSE's power costs for 2007 should be based upon Mid-C forward prices and not AURORA derived hourly values.

C. Consistent With Gas Cost Determination

Q. How has PSE determined gas costs for the rate period?

A. As it has done for the past several cases, PSE is relying on forward market prices in order to calculate it gas costs for the rate period. In past proceedings, the forward prices were derived from New York Mercantile Exchange prices quoted for delivery at the Henry hub in Louisiana. PSE would then derive a basis differential to reflect the price of gas at western trading hubs. In this application, PSE is using forward prices directly for these western hubs as supplied by Kiodex. Kiodex specializes in providing forward prices for a number of electric and gas hubs throughout the United States.

Q. Does Kiodex produce forward electricity prices for the Mid-C hub?

A. Yes. Kiodex produces both on and off peak forward prices for all the major western trading hubs, including Mid-C.

Q. Have you performed any comparative evaluation of the Kiodex forward price projections?

A. Yes. The Joint Parties compared Kiodex forward prices with those published by Platt's Energy Trader for the Mid-C hub. While the data was not identical, the analysis showed very little variation in prices from these two different sources. The Joint Parties view this close congruence between two competing information providers as a further indication of the robustness of the Mid-C hub forward prices.

Q. Should the forward electricity prices be used to determine PSE's power cost?

A. Yes. The electricity markets are sufficiently robust such that the forward prices can be used to determine PSE's power cost. The Joint Parties believe it is necessary to have consistency between how gas prices and electricity prices are determined.

Several years ago, ICNU proposed using a fundamentals model to determine gas prices. PSE strongly objected to this approach stating that gas forward prices were a fairer measure of expected costs. At that time, fundamental gas modeling produced prices lower than the forward market prices. The Commission accepted PSE's arguments. We are now at a point when forward electricity market prices can be relied upon in lieu of a fundamentals electricity market model subject to the biases of the modeler. For improved accuracy, avoidance of bias, and consistency with how gas costs are determined, the Joint Parties recommend that the same three month average of gas forward prices be applied using Kiodex's on and off-peak forward monthly electricity prices for calculating PSE's purchase power costs in this proceeding. Under this recommendation, both significant cost drivers---gas costs and electricity prices—will be based upon unbiased market values.

D. Cost Savings & Error Minimization

Q. Are there any other reasons why the Joint Parties believe forward prices should replace the AURORA derived values?

A. Yes. Use of forward electricity prices to value PSE's power purchases will lessen the need to scrutinize every line of the AURORA data set. This will result in a cost saving from not requiring such a time intensive effort and it will minimize or dampen the errors associated with improper resource specifications.

Q. Why will it minimize the impacts on data set errors?

A. The primary result of these errors will be the hourly prices derived by AURORA.

Since these values will be replaced with forward prices, the error impacts are lessened. This can be illustrated by applying the forward price adjustment to PSE's Updated cost projection and comparing it to the Joint Parties recommendations in this proceeding. There are at least two approaches for performing the adjustment. One approach would be to use the prices as an input to the AURORA model. Under this option, the model would determine the dispatch of all resources based upon these values. While more current versions of the AURORA model can accommodate this option, we understand it to be cumbersome with the version being used by all parties in this proceeding.

A second approach would simply be to apply a post processing adjustment to the AURORA result just as PSE does for its fixed contract purchases. That is, all AURORA determined "market" purchases beyond the fixed contract amounts would be priced at the forward price series instead of the AURORA prices. By doing the adjustment in this manner, the AURORA produced system dispatch and opportunity sales amounts are not altered. The Joint Parties recommend this second method be approved by the Commission for calculating PSE's market purchase cost in this proceeding. Application of this method to PSE's Update filing lowers PSE's power costs by $17.4 million. This calculation is presented in Exhibit No. __ (Joint-16C). Applying this approach to the Joint Parties AURORA prices produces a reduction of only $11.7 million. This calculation is presented in Exhibit No. __ (Joint-17C). The lower result of this adjustment occurs for the Joint Parties costs since the other AURORA data corrections had already reduced the AURORA derived PSE power costs by $9.9 million. The entire Joint Parties recommendations reduce PSE's power costs by just $21.6 million. Thus, a substantial portion of the value from correcting the data specifications is compensated for by replacing the resulting AURORA derived values with forward market prices. This suggests the parties need not necessarily go through the AURORA data set with a "fine tooth comb" looking for every poor or erroneous specification.

VI. PEAKING COSTS

Q. Has PSE included any costs for meeting extreme peaks in its filing?

A. Yes. PSE has included $1.1 million in the Update filing for meeting a capacity deficit in December 2007 assuming a temperature of 12 degrees. (See Exhibit No. __ (DEM-17), page 3, line 43.)

Q. What method did PSE use to estimate the extreme peak load?

A. PSE used its 2005 least cost plan methodology to forecast extreme peak loads arising from this extreme peak temperature assumption. The Joint Parties recommend that PSE should change or modify its approach to determining peak load in its next rate case filing.

Q. Please explain the reasons for the Joint Parties recommendation to change the method of estimating extreme peak load.

A. PSE estimates peak load based on various design temperatures. However, it is not clear to the Joint Parties the probabilities of observing these cold days in any given year. The result could well be that expenses are included in the base power cost with only a remote likelihood that the costs will be realized. A better approach is to calculate the likely peak temperature based on the historical record of at least 30 years to be consistent with temperature normalization methodology. Then, a reasonable probability can be selected for determining the allowable peaking costs to be included in the base power cost determination.

Q. Are there revenue requirement impacts resulting from this recommended change to PSE's method of determining peak load?

A. No. The Joint Parties recommend that this approach be used in future filings and that all interested parties work together to determine a specific peak temperature to employ in the capacity cost calculation from an analysis of the historical data.

Q. Are there other adjustments to PSE's production O&M costs?

A. Yes. There are adjustments to PSE's request for Baker hydro relicensing and Muckleshoot settlement costs, but Mr. James Russell will testify to these matters.

Q. Have you prepared an exhibit comparing the Joint Parties proposed adjustments related to PSE's power cost?

A. Yes. Exhibit No. __ (Joint-18) compares the power cost resulting from the Joint Parties recommendations with PSE's Update cost. As previously noted, it reduces power costs by $21.6 million. After accounting for the production factor adjustment and revenue sensitive taxes, it translates into a reduced revenue need of $22.3 million.

Q. Does this conclude your testimony?

A. Yes, at this time.