EXHIBIT NO. _______ (WAG-18T)
DOCKET NO. UE-031725
2003 POWER COST ONLY RATE CASE
WITNESS: WILLIAM A. GAINES

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-031725

REBUTTAL TESTIMONY OF
WILLIAM A. GAINES
ON BEHALF OF PUGET SOUND ENERGY, INC.

FEBRUARY 13, 2004

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PUGET SOUND ENERGY, INC.

REBUTTAL TESTIMONY OF WILLIAM A. GAINES

I. INTRODUCTION

Q: Are you the same William A. Gaines who submitted direct and supplemental testimony in this proceeding on behalf of Puget Sound Energy, Inc. ("PSE" or "the Company")?

A: Yes, I am.

Q: What is at issue in this proceeding?

A: This proceeding began as a review of PSE's proposed update to its PCA Power Cost Rate for the period beginning April 2004. Our power cost only rate filing centered on PSE's acquisition of an interest in the Frederickson 1 resource and updates to other power costs that would establish PSE's "2004 PCORC Baseline Rate".

In addition, the parties in PSE's PCA compliance proceeding (Docket No. UE-031389) were able to settle all but one issue regarding PSE's 2003 PCA Report, which trues up the PCA deferral calculation from the first PCA period, July 1, 2002 to June 31, 2003 ("2003 PCA true-up"). That issue, which was added to this 2004 PCORC proceeding just last month, centers around the amount of fuel supply costs the Company incurred for the operation of its Tenaska and Encogen combined cycle combustion turbines to be included in the 2003 PCA true-up.

Q: What is the purpose of your rebuttal testimony?

A: I am submitting this rebuttal testimony for three reasons: 1) to identify those adjustments to power costs to which PSE agrees and provide information about the resulting impacts to the updated power costs for the 2004 PCORC Baseline Rate; 2) to respond to concerns that have been raised regarding PSE's recovery, in the 2004 PCORC Baseline Rate and in the 2003 PCA true-up, of portions of the fuel supply costs it incurs for operation of its Tenaska and Encogen combined cycle combustion turbines; and 3) to respond to concerns that have been raised about PSE's gas pricing methodology (and the gas price that PSE projected using this methodology) for the 2004 PCORC Baseline Rate.

II. POWER COST ADJUSTMENTS TO WHICH PSE AGREES

Q: Does PSE agree to a number of the pro forma power cost adjustments proposed by the other parties?

A: Yes. PSE agrees with a number of pro forma power cost adjustments proposed by Commission Staff and by ICNU for the 2004 PCORC Baseline Rate. These adjustments relate to the Colstrip 3 maintenance outage period, the March Point 1 generation level, and the application of the prudence disallowance established in the Commission's Nineteenth Supplemental Order in Docket No. UE-921262 et al. ("1994 Prudence Order") to the March Point Phase 2 and Tenaska replacement power costs.

Q: Please describe PSE's agreement concerning the Colstrip 3 maintenance outage period.

A: On page 12 of his testimony for Commission Staff, Mr. McIntosh recommends that the maintenance period for Colstrip 3 be reduced to the 44 days projected by the project operator for the rate year – or 624 hours less than PSE's predicted maintenance time set forth in my initial testimony workpapers. *See* Ex. T___ (HM-1TC/HC) at 12. While PSE still believes that the maintenance outage will exceed the projected 44-day period, PSE agrees to Commission Staff's recommended maintenance period for ratemaking purposes for the 2004 PCORC Baseline Rate. The total estimated increase in Colstrip 3 generation due to this change is approximately 99,820 MWh during the 2004 PCORC rate year. In addition, the change in the assumed availability of Colstrip 3 also increases the assumed amount of power delivered under PSE's contract with NorthWestern Energy (MPC Firm Contract) by about 9,360 MWh during the 2004 PCORC rate year.

Q: Please describe the March Point 1 generation adjustment to which PSE agrees.

A: On pages 10-12 of his testimony, ICNU's witness, Mr. Schoenbeck, recommends that the expected energy from March Point 1 be reduced to reflect a normalized production value lower than that proposed by PSE in my original testimony work papers. PSE agrees to reduce the capacity of, and maximum energy from, March Point 1 from 86 to 80 MW for the 2004 PCORC rate year. This change reduces the energy from March Point 1 for the 2004 PCORC rate year from 740,729 MWh to approximately 689,051 MWh.

Q: What adjustments should be made to the replacement power costs for March Point Phase 2 and Tenaska?

A: On page 12 of his testimony for Commission Staff, Mr. McIntosh points out that PSE did not apply the 1.2% and 3.0% disallowances established in the 1994 Prudence Order to the replacement power costs for Tenaska and March Point Phase 2, respectively. *See* Ex. T___ (HM-1TC/HC) at 14-15. PSE agrees with this adjustment for the disallowance set forth in the 1994 Prudence Order.

Q: Has the Company discussed these adjustments with Commission Staff?

A: Yes. I understand that Mr. McIntosh agrees with how we have made these adjustments.

Q: Do these adjustments result in a revised forecast of power costs for the 2004 PCORC rate year?

A: Yes. To determine the updated power costs for the 2004 PCORC Baseline Rate, PSE has run the AURORA model with these new inputs (revised assumptions) to the AURORA database. The results of the new AURORA model run and changes to non-AURORA power costs are reflected in **Ex. ___ (WAG-19)** and **Ex. ___ (WAG-20)**. (These exhibits are attached to my rebuttal testimony and represent revisions to **Ex. ___ (WAG-15)** and **Ex. ___ (WAG-16)**, respectively, which I submitted with my direct testimony.) These adjustments amount to a $12,230,000 reduction in total power costs for the 2004 PCORC Baseline Rate rate year compared to the costs proposed in my initial testimony. The agreed Tenaska and March Point Phase 2 Prudence Order disallowances are deducted on lines 17 -18 of **Ex. __(WAG-19)**.

Q: Have you made other adjustments to Ex. ___ (WAG-15)?

A: Yes. As Ms. Ryan discusses in her rebuttal testimony, PSE has reduced its forecasted level of winter peaking capacity costs. *See* **Ex. ___ (JMR-11T)** at 2-3. This lower level of capacity costs is also reflected in **Ex. ___ (WAG-19)**. As Mr. Story discusses in his rebuttal testimony, PSE has reduced its forecasted major maintenance costs associated with combustion turbines. *See* **Ex. ___ (JHS-10T)** at 4-5. This lower level of maintenance costs is also reflected in **Ex. ___ (WAG-19)**. In addition, I have made other minor adjustments (totaling $156,000) due to changes which result from the AURORA output reflecting the adjustments described above. As shown on the same exhibit at line 22, the revised total power costs for the 2004 PCORC rate year total $743,125,000.

III. TENASKA AND ENCOGEN COSTS

A. Introduction

Q: What is the purpose of this section of your testimony?

A: I respond to assertions that PSE should not be permitted to recover, for both the 2004 PCORC Baseline rate year and the 2003 PCA true-up period, portions of the fuel supply costs it incurs for operation of its Tenaska and Encogen combined cycle combustion turbines.

Q: Please summarize your conclusions with respect to the Tenaska and Encogen issues.

A: I conclude the following:

- The Commission's disallowance for Tenaska in the 1994 Prudence Order is a 1.2% disallowance on net contract charges, not a fixed price ceiling or cap.

- PSE's restructuring of the Tenaska and Encogen cogeneration plant contracts were prudent decisions, as was PSE's management of gas supply for Tenaska and Encogen during the period after the buyouts of those contracts in late 1997 and 1999.
- PSE should be permitted to recover its fuel supply costs associated with these units, reduced (as described below) by 1.2% of net contract charges for Tenaska pursuant to the 1994 Prudence Order.

B. The Commission's 1994 Prudence Order Imposed a Percentage Disallowance of PSE's Tenaska Net Contract Charge

Q: Please describe the Tenaska Plant and the Tenaska Agreement.

A: The Tenaska Plant is a 245 MW natural gas-fired cogeneration plant located adjacent to the Tosco Refinery near Ferndale, Washington that is owned and operated by Tenaska Washington Partners, L.P. Puget Sound Power & Light Company (PSE's predecessor which I will refer to as "Puget") entered into a long-term Agreement for Firm Power Purchase on March 20, 1991, pursuant to the Public Utilities Regulatory Policy Act (PURPA), for Puget's purchase of power from the Tenaska Plant. The Tenaska Agreement provided for a term ending in 2011.

Q: What facts gave rise to the Commission's disallowance of Tenaska-related costs?

A: Puget filed a general rate case in 1992 in which Puget sought to recover in its rates the costs of the power that it purchased under the Tenaska Agreement. In the 1994 Prudence Order, the Commission found that Puget paid too much for the Tenaska Agreement because it should have "factor[ed] in the value of dispatchability" during the acquisition process. (1994 Prudence Order at page 32.)

Q: What disallowance did the Commission provide for in the 1994 Prudence Order?

A: After considering a number of possible approaches, the Commission decided that for future ratemaking, there should be a disallowance of "1.2% of net contract charge for Tenaska. The net charge is the amount paid to the contractor, Tenaska …, plus any payments for replacement power resulting from economic dispatch." (1994 Prudence Order at page 32.) The Commission's Finding of Fact No. 8 (at page 46) tracked this approach: "Future ratemaking treatment for these contracts should include percentage disallowances to reflect the excess amounts, as follows: Tenaska 1.2%…".

Q: Did the Commission explain why it used a percentage factor to determine the disallowance?

A: Yes. After the Commission issued the 1994 Prudence Order, Puget filed a motion that asked the Commission to clarify the 1994 Prudence Order's language regarding "net contract charges." In its Twentieth Supplemental Order, the Commission explained that it could have calculated the disallowance in several ways: "Or, per the order, the disallowance could be calculated as a percentage of the net cost of the contract. This type of disallowance will reward the company for any dispatchability that occurs by reducing the disallowance for the benefits of dispatchability, but only if the dispatch is economical." (Twentieth Supplemental Order at page 18.) The Commission revised its Finding of Fact No. 8 in the 1994 Prudence Order to read:

> Future ratemaking treatment for these contracts should include percentage disallowances to reflect the excess amounts. Those disallowances are: Tenaska 1.2% and March Point Phase II 3.0%. In both cases, the disallowance is calculated as a percentage of the net cost of the contract. The net cost of the contract includes the following three components: (1) the amount paid to the contractor for energy actually purchased at the contract rate; (2) the amount paid to the contractor under the contract's displacement provisions; and (3) the amount paid for replacement power when economic dispatch occurs.

(Twentieth Supplemental Order at page 18.)

Q: Did the 1994 Prudence Order impose a fixed dollar amount disallowance or cap or ceiling upon future recoverable costs for the Tenaska Agreement?

A: No. The 1994 Prudence Order only imposed a percentage disallowance of certain of PSE's actual costs under the Tenaska Agreement. The Commission's disallowance is the product of 1.2% multiplied times "(1) the amount paid to the contractor for energy actually purchased at the contract rate; (2) the amount paid to the contractor under the contract's displacement provisions; and (3) the amount paid for replacement power when economic dispatch occurs."

Q: Can you summarize how the 1994 Prudence Order has been applied?

A. Yes. During the last ten years, it has consistently been applied as the product of the net contract charge multiplied times the 1.2% percentage factor, as Mr. Story describes in his rebuttal testimony. *See* **Ex. __ (JHS-11T)** at 12-14**.**

Q: Did the 1997 or 1999 accounting order proceedings for the Tenaska and Encogen/Cabot fuel contract buyouts give the Company any reason to believe that there would be a cap on recovery of fuel costs incurred after the buyouts?

A: No.

Q: Did the 1997 accounting order proceeding for the Tenaska fuel contract buyout give the Company any reason to believe that the 1994 Prudence Order disallowance percentage would be applied to the regulatory asset established in that accounting order?

A: No.

C. No Party Has Challenged the Prudency of PSE's Tenaska Fuel Supply Agreement Buyout, PSE's Purchase of the Encogen Plant, or PSE's Buyout of the Cabot Fuel Supply Agreement for Encogen

Q: Have the opposing parties challenged PSE's decisions related to restructuring the Tenaska and Encogen agreements?

A: No. None of the opposing parties argue that PSE's buyout of the Tenaska fuel supply contract in 1997 was imprudent. Instead they claim that PSE should have locked in a long-term fixed price agreement for fuel supply for Tenaska at a fixed cost in late 1997 or early 1998 after the buyout. Similarly, none of the parties claim that PSE's purchase of the Encogen plant or subsequent buyout of the Cabot fuel supply contract for the plant in 1999 were imprudent. Instead, Mr. Elgin asserts that PSE has not shown that its management of fuel supply for Encogen after the buyout of the Cabot fuel supply contract has been prudent.

PSE presented evidence in its direct case in this 2004 PCORC proceeding regarding the buyout decisions, including incorporating by reference the Company's contemporaneous analyses supporting the buyouts that were filed with the Commission in the accounting dockets. *See* **Ex. ___ (WAG-1T)** at 28-29; **Ex. ___ (WAG-10)** at 6. Opposing parties issued data requests relating to the buyout decisions and PSE prepared detailed responses to those requests. *See* **Ex. ___ (WAG-21C); Ex. ___ (WAG-22C)**; **Ex. ___ (WAG-23C)**.

D. The Context of the Company's Decisions Regarding Fuel Supply for Tenaska and Encogen

Q: Please describe the context in which the Company makes decisions regarding management of its fuel supply.

A: Those making resource management decisions for the Company do not have the luxury of managing its resources with any (let alone perfect) hindsight, nor with perfect foresight. In conducting the Company's day-to-day operations, we have information available to us at the time about circumstances in the industry, projections (sometimes conflicting) regarding future conditions in the gas and power markets, future retail load, and a variety of other matters. Often, individual pieces of information do not clearly add up to a solid conclusion regarding the future direction of natural gas or power prices. The Commission has recognized that care must be taken to examine such decisions in the context of circumstances that existed at the time rather than with the benefit of information that became available or certain only after the decisions were made.

In my experience, transactions to obtain a fixed price for power or fuel (whether a physical or financial transaction) that are reasonable at the time they were entered into may well appear unfavorable in retrospect when future market conditions (which were unknowable at the time the transaction was entered into) differ from and are less than the fixed price. Similarly, I do not believe that our historical decisions not to enter into a long term, fixed-price transaction for Tenaska or Encogen should be found imprudent just because it turns out in hindsight that market conditions become less favorable than a fixed price that may have been available at some point in the past.

Q: Are you sponsoring an exhibit to assist in understanding the timing of actions by PSE regarding Tenaska and Encogen and their relation to various events in the industry?

A: Yes. In **Ex. ___ (WAG-24)**, I have provided a timeline that places PSE's buyouts of the Tenaska and Encogen contracts as well as PSE's subsequent management of this fuel supply in the context of events taking place in the industry. This timeline also includes a chart showing actual historic Sumas Gas Daily and NYMEX Henry Hub monthly settled prices for natural gas from 1991 through 2003. The information on this chart that precedes any point in time illustrates historical information available at that point in time. This chart is meant to assist the Commission in understanding the historical and contextual information in which the Company made decisions.

E. PSE's Management of Fuel Supply from Late 1997 through Early 2000

Q: Was the Commission's approval of PSE's Tenaska accounting petition premised on an understanding that PSE would be locking in future fuel prices for the unit? (*See* Ex. T___ (KLE-1T) at 3; Ex. __ (JL-1TC) at 3)

A: No. In the open meeting at which the Commission considered and approved PSE's accounting petition for Tenaska, Commissioner Hemstad, Mr. Schooley and PSE representative Karl Karzmar specifically discussed management of fuel costs for Tenaska after the buyout. Commissioner Hemstad posed the question of whether the Company intended to "lock in [the estimated] prices now." Mr. Karzmar responded: "[T]he company's intention at this time was not to lock in those prices, although that would be an option. That kind of looks like what we had before. We had locked in forward prices then. We would like to manage this with the rest of our portfolio. That would be the company's preference." *See* Transcript of Dec. 10, 1997 Open Meeting at 3-5 (**Ex. ___ (WAG-25)**).

Q: Did PSE guarantee in 1997 that the estimated power cost savings from the Tenaska buyout would in fact be realized?

A: No. The Company recognized that the actual savings achieved from the buyout would depend on market prices. PSE stated at the time with respect to its forward market gas price quotes and estimated savings presented in Docket No. UE-971619: "If the Company can better these prices in the market, the savings will be greater. Conversely if prices go up, there will be less savings." **Ex. ___ (WAG-26)**.

Q: Do you agree with Mr. Elgin that "[t]he Company did not present sufficient evidence in its direct case or in discovery that [its] fuel costs were prudently incurred or reasonable in amount?" (*See* Ex. T___ (KLE-1T) at 9)

A: No. My direct testimony presented an overview of PSE's resource management activities beginning in the 1990s, throughout the push toward industry restructuring, the Western Power Market Crisis, and since then. *See* **Ex. ___ (WAG-1T)** at 6-8. As I stated there, it appeared to PSE in the late 1990s that:

> the most reasonable way to provide customers with least cost, reliable electric power would be through PSE's expanded participation in (and reliance upon) the wholesale power markets, and by a reduction in PSE's dependence upon long-term, fixed-cost generating resources.

See **Ex. ___ (WAG-1T)** at 7. My direct testimony also described PSE's management of its energy supply portfolio and a number of steps PSE had taken to manage risks associated with evolving electric power markets, including establishment of PSE's Risk Management Committee ("RMC"). *See* **Ex. (WAG-1T)** at 7-8. Later in my direct testimony, I described drivers of volatility in PSE's power supply portfolio and risks associated with such variables. *See* **Ex. ___ (WAG-1T)** at 19-23. Other Company testimony and exhibits presented even more detail regarding the Company's more recent risk management activities. *See* **Ex. ___ (JMR-1T)** at 6-18; **Ex. ___ (JMR-3C)**; **Ex. ___ (JMR-4)**; **Ex. ___ (CJB-3)**.

In discovery responses in this 2004 PCORC proceeding and in the 2003 PCA true-up docket, PSE provided information regarding its management of fuel supply for Tenaska and Encogen since the buyout and its risk management activities since the mid-1990s. This information includes the following:

Exhibit	**PSE Response to:**	**Topic**
Ex. __ (WAG-27)	WUTC Staff DR 45 (12/17/03)	a history of PSE's risk management activities from 1995 to the present
Ex. __ (WAG-28C)	WUTC Staff DR 48 (12/17/03)	risk management manuals for the period 1995 to 2003
Ex. __ (JMR-12)	WUTC Staff DR 33 (12/11/03)	PSE's techniques for risk management of gas supply portfolio serving combustion turbines
Ex. __ (JMR-13)	WUTC Staff DR 34 (12/11/03)	PSE's algorithms, strategies and tools for optimizing its portfolio
Ex. __ (JMR-14)	WUTC Staff DR 51 (12/17/03)	Analysis of price benefits of long-term gas supply options after 2000-01 extremes
Ex. __ (JMR-15)	WUTC Staff DR 58 (WUTC Staff DRs 12 and 13 from UE-031389) (10/31/03)	Data and documents re management of fuel supply for Tenaska and Encogen after buy outs

I am co-sponsoring with Ms. Ryan the above exhibits as to time periods prior to 2002.

Q: Should the Company have locked in a long-term fixed-price fuel supply contract for Tenaska in late 1997 or early 1998, immediately after the Tenaska buyout?

A: No. As explained in greater detail below, I do not believe it would have been advisable for PSE to immediately replace its Tenaska fixed-price fuel supply contract with a new fixed-price commitment due to the following:

- The state of the industry at that time;
- Market conditions at that time; and
- The position of Tenaska within PSE's resource stack.

Q: What was PSE's understanding of the state of the industry at the time it restructured the Tenaska contract?

A: The natural gas and electric industries were in a state of upheaval, which presented fundamental uncertainties. Based on what was and had been occurring in these industries, PSE believed it was important to move the Tenaska fuel supply to market-based pricing and not lock in a long-term, fixed price commitment for fuel supply for the plant. *See generally* **Ex. ___(WAG-29)** (excerpts from PSE's 2000-01 Least Cost Plan). In **Ex. ___(WAG-30)**, I describe in greater detail various industry events during that period with which I and others at the Company were familiar.

Q: Please summarize what was happening in the industry at that time.

A: By the mid 1990s, the natural gas industry had been deregulated, gas prices were falling, and gas prices were projected to stay low into the future. FERC, as well as various states and market participants throughout the country, were pushing toward deregulation in the electric industry as well. Many states moved rapidly toward retail restructuring, and similar legislative efforts were being explored in Washington State at the time. In the event that Washington State moved (or was forced to move) to retail competition, PSE was faced with the prospect of stranded costs and the potential adverse impact on the Company and its ability to serve its remaining retail customers. Indeed, the Commission stated in late 1995:

> [R]egulation cannot and should not be expected to guarantee utilities will, in all circumstances, be made entirely whole for generation or other costs that are determined through actual and fair competition to be stranded or uneconomic.

(**Ex. ___ (WAG-30B)** at 2.)

Q: How did pressures to move toward retail competition affect PSE?

A: As wholesale power prices in the mid-1990s moved lower than rates for power charged by traditional utilities based on embedded, historical power costs, retail electric customers, particularly large industrial customers, began pressing for access to market-based rates rather than rates based on embedded costs of service. A number of customers began exploring opportunities to bypass PSE's system if they were not granted access to market-based rates. PSE developed Schedule 48 to meet the industrial customers' demand. This rate schedule was predicated upon providing market-sensitive pricing to large customers.

At the time, Public Counsel objected that only PSE's industrial customers were gaining access to market based rates and argued: "Market based rates should be developed for all customers and offered at substantially the same time." (**Ex. ___ (WAG-30D)** at 3.) In late 1996, the Steering Committee of the Comprehensive Review of the Northwest Energy System recommended that "regulators and local utility boards and commissions offer open access for all customers that desire it no later than July 1, 1999." (**Ex. ___ (WAG-30B)** at 5.)

Q: Please continue your summary of the industry at that time.

A: Around the same time, PSE's long-term fixed price PURPA contracts were criticized as uneconomic and inflexible. In proceedings on the requested approval of the merger between Washington Energy Company and Puget Power, the Commission Staff witness testified:

> The price increases associated with Puget's PURPA resource contracts are a major source of continued upward rate pressure, and contribute to Puget having the highest retail electric rates in the region.
>
> …
>
> The wide discrepancy between the embedded cost of power in rates and market prices, and power contract-related rate pressures, are occurring during a period of low short-run prices for power in the regional market. The low prices result from federal government open transmission access initiatives, a surplus of generating capacity in the region, the increasing presence of power marketers and brokers, and continued low natural gas prices. *To the extent that the terms and conditions of its long-term PURPA contracts limit the Company's ability to take advantage of low wholesale spot market prices, core customers have little opportunity to achieve lower rates.*

(**Ex. ___ (WAG-30F)** at 2-3 (emphasis added).)

In sum, PSE and its predecessors had to make business decisions on an ongoing basis during the 1990s in a period of massive upheaval and change in the natural gas and electric industries. As the Commission stated at the time: "The pace and scope of change in the electric industry has been faster and broader than the Commission could have imagined." (**Ex. ___ (WAG-30B)** at 4.) PSE's resource decisions at the time were reflective of this environment, in which its future requirements to provide retail open access, market-based rates and/or traditional embedded cost service to customers were uncertain.

Q: How did PSE respond to these uncertainties?

A: Among other things, PSE sought to reduce its dependence upon fixed-price long-term natural gas supplies under its PURPA contracts. Moving the Tenaska (and later the Encogen/Cabot) fuel supply costs to market was an important step in that direction. By purchasing gas in short-term markets, as opposed to purchases through contracts for long-term fixed prices, PSE positioned itself to take greater advantage of gas prices in the short-term market and to have increased flexibility to address rapidly changing and uncertain industry circumstances.

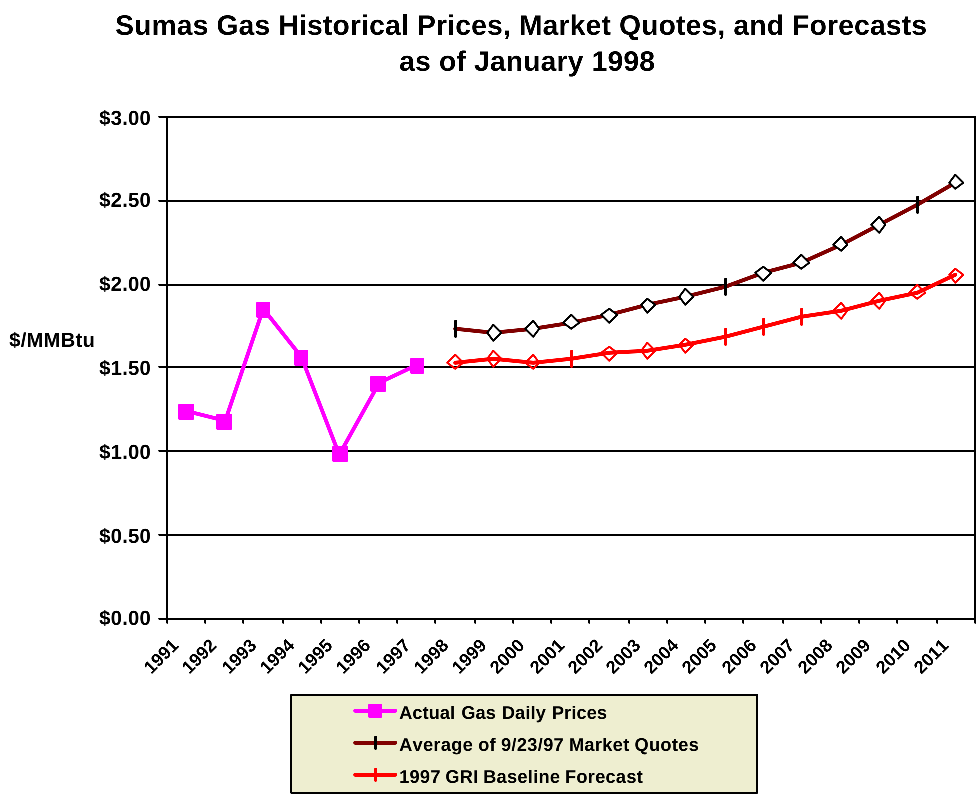
PSE's 2000-01 Gas and Electric Least Cost Plan ("2000-01 LCP") analyzed the significance of industry events with respect to PSE and the need for flexibility to address these risks and uncertainties. The 2000-01 LCP was filed with the Commission in December 1999 and reflected the Company's ongoing analysis of such issues in the late 1990s. Noting that the Company's traditional resource portfolio contained little market-responsive supply sources, the 2000-01 LCP reviewed the state of the industry and observed:

> In the absence of a resolution of these issues, PSE must manage its electric supply portfolio to be responsive to its customer supply commitments as they are expected at the current time, recognizing fundamental uncertainties. This uncertainty drives a need for additional flexibility in PSE's electric supply portfolio.

See **Ex. ___ (WAG-29)** at 9. As illustrated in **Ex. ___ (WAG-31)**, moving Tenaska and Encogen/Cabot fuel supply to market provided an incremental adjustment to PSE's resource portfolios toward market-based prices. Even so, the bulk of the Company's resources continued to be fixed-cost resources.

Q: What market conditions did PSE observe at the time of the Tenaska buyout?

A: At the time of the Tenaska restructuring, the Sumas gas market exhibited very low spot prices, and had been exhibiting low prices for quite some time, including periods of falling prices. The spot price for gas averaged $1.03/MMBtu in 1995, $1.35/MMBtu in 1996, and $1.51/MMBtu in 1997. The long term price quotes PSE received in September 1997 in connection with its analysis of the Tenaska buyout started well above these recent historical levels, averaging $1.73/MMBtu for 1998 and escalating from that point. *See* **Ex. __ (WAG-32C)** at 2. Contemporaneous gas price forecasts from the Gas Research Institute predicted prices lower than the then-current forward market quotes. *See* **Ex. __ (WAG-33C)**. The chart at **Ex. ___ (WAG-34)**, which is reproduced below, illustrates the historic information PSE possessed during late 1997 and early 1998 as well as these forward predictions of future market prices, compared with the premium required to lock in a long-term fixed-price contract:



Because PSE had received long-term quotes with a significant premium versus current and forecasted gas prices, in an environment of many years of relatively stable prices and even falling prices, it did not appear advisable at that time to lock the Company back into fixed-price, escalating contracts rather than purchasing and hedging gas on the near-term market.

Q: What was Tenaska's position in PSE's resource stack?

A: By the late 1990s, Tenaska was one of PSE's marginal resources on an operating cost basis. Thus, generally speaking, Tenaska was one of the resources that PSE would displace if warranted by the spark spread.

Q: What was the significance of that position with respect to PSE's management of fuel supply for the facility?

A: At that time, the short-term and forward wholesale electric and gas markets in the Northwest region had become much more active and robust, which allowed the Company to take better advantage of the interaction between the relative prices of power and gas versus the efficiency of the Tenaska plant. Essentially, in the absence of long-term fixed-price fuel supply contracts, the economic question at any given moment is whether it is less expensive to purchase gas and generate power or to displace the generation and purchase the power on the market (rather than generating it). When projected market heat rates are low, the likelihood of PSE using all of its gas-fired generation drops, and hence the purchase needs for gas as a generation fuel drop. Indeed, if the Company has committed to purchase gas fuel in fixed amounts or at fixed prices that becomes surplus to PSE's needs to serve its retail load, without simultaneously fixing the price at which the resulting surplus power is sold, then the Company has actually increased rather than decreased its risk.

At the time, PSE was faced with significant load and resource uncertainties but expected to have resources in excess of loads for some period to come. *See* **Ex. __ (WAG-36C)**. For example, PSE did not know what would develop with respect to its Schedule 48 customers. There were also indications at the time that PSE's Residential Exchange benefits from the Bonneville Power Administration ("BPA") could well be provided at least in part through power deliveries from BPA rather than cash payments. *See* **Ex. __ (WAG-37)**. This would have added approximately 300 MW of fixed-price resource to PSE's system, making displacement of Tenaska even more likely.

In addition, and regardless of PSE's overall resource position, PSE's load peaks in the winter and is lower in the summer. Also, in the spring PSE typically has significant hydroelectric generation that tends, during normal to surplus hydro seasons, to displace resources such as Tenaska.

By obtaining its fuel supply for Tenaska through spot market purchases and near-term (monthly and seasonal) hedging, PSE was able to actively manage its spark spread and the seasonal fluctuation in its load and reduce its risks.

Q: Would you please summarize your answers above regarding the reasons why it was reasonable at the time that the Company did not lock in a long-term fixed-price fuel supply contract for Tenaska in late 1997 and early 1998?

A: Considering the state of the industry at the time, market conditions at the time, and the position of Tenaska within PSE's resource stack, PSE's decision to avoid locking in a long-term gas contract to supply Tenaska after the buyout in late 1997 and early 1998 was reasonable.

Q: Can the Company's Tenaska and Encogen fuel management decisions be evaluated solely by reference to decisions for those specific plants?

A: No. The Company's management of its fuel supply for Tenaska and Encogen took place in the context of its broader risk management efforts. As wholesale electric markets started to mature, PSE continuously reviewed and changed how it managed fuel and power requirements and sought to develop tools and systems to better manage risks associated with its resources.

PSE established its Risk Management Committee ("RMC") in 1997 and its Energy Risk Management ("ERM") Department in 1999. (Ms. Ryan's direct testimony describes the analysis and evaluation performed by the ERM Department, which is overseen by PSE's RMC. *See* **Ex. ___ (JMR-1T)**.) From late 1997 on, the RMC and Company staff working under the RMC's oversight monitored issues and explored solutions related to uncertainty and volatility in PSE's portfolio, including commodity prices and forward positions. The RMC supervised development of procedures and systems to improve and enhance reporting and analysis of PSE's position, developed policy with regard to entering into forward transactions to hedge risks, and oversaw implementation of the RMC's policies. The ERM and RMC considered information available from third-party sources in the industry about variables such as power and gas price forecasts and trends, rig counts, and generation plant additions. This information was incorporated into PSE's decisionmaking. *See* **Ex. __ (WAG-36C)**. (Since 2001, the ERM Department has conducted the "fundamental analysis" that Ms. Ryan describes in her rebuttal testimony. *See* **Ex. ___ (JMR-11T)** at 7-8.

In the mid-1990s, PSE tracked its daily electric trading using Excel spreadsheets and the Company's Energy Scheduling and Accounting System (ESA). In September 1997, the Company added the Louis Dreyfus Electric scheduling system (LDEC), which allowed the Company to monitor and manage its daily and forward electric load and resource physical position and trades. PSE used LDEC to implement "mark-to-market" valuation and related trading controls and limits and to develop daily position reports. In addition, during the 1997-2000 time period, the Company used a variety of Excel spreadsheets and Access database tools to analyze PSE's loads and resources, the operating cost of various units, displacement potential, forward market prices and market price forecasts for power and gas, hydro forecasts. PSE further used these tools to determine if more value could be extracted from Tenaska and other resources through the use of financial hedging tools such as puts and calls. *See, e.g.,* **Ex. ___ (WAG-35C)**.

Q: Did PSE seek outside expertise to assist in these efforts?

A: Yes. In 1997-99, PSE worked with Duke Louis Dreyfus (later Duke Energy Trading and Marketing) on wholesale power marketing and forward trading of power resources, and forward position analysis.

In mid-1999, PSE also engaged the services of a company named Merchant Energy Group of the Americas (MEGA) to provide risk advisory services to PSE. MEGA provided support and advice in the areas of risk control, energy accounting system development and design, development of credit policies and procedures, portfolio analysis, and the development of intermediate-term hedging strategies and recommendations. Specific issues that were addressed included master agreement setup, credit exposure and credit tracking systems, trader responsibilities, trade transaction processes, transaction recording and tracking systems procedures, compilation of positions, invoice preparation, and cash management. MEGA and PSE risk management staff also initiated a process to review and potentially revise the Company's 1997 Energy Price Risk Policy.

Q: Did the Company rely on the spot market to procure gas supply for Tenaska after the buyout in late 1997? (*See* Ex. ___ (DWS-1T) at 29)

A: No. After the buyout, the Company procured gas supply for Tenaska through the wholesale market and its various product offerings, applying the risk management considerations, tools and techniques that I discussed above. PSE purchased gas on the spot market, periodically locked in physical supply contracts with a price tied to a market index, and also locked in short-term supplies at fixed prices. Initially, such hedging was accomplished through fixed-price physical contracts. Also, in the late 1990s, PSE also began to utilize financial derivative ("swap") contracts, which contained floating-to-fixed price hedges. The amount and timing of these various types of gas purchases were highly dependent upon the projected amount of consumption of gas for the Tenaska plant and were largely based on the projected market heat rates and expectations regarding forward and potential spot prices. **Ex. __ (WAG-39C)** contains specific examples of specific Tenaska hedging decision documents from the 1998-99 time period that PSE has been able to locate.

Q: Was it reasonable for the Company to continue the post-buyout Tenaska fuel supply strategy that you discussed above?

A: Yes. The factors described above that led PSE to keep Tenaska fuel at market rather than locking in a long term contract continued. *See* **Ex. __ (WAG-29)**. Natural gas price forecasts that PSE reviewed in late 1999 and into early 2000 indicated that there might be short-term spikes or volatility in market prices for gas, but that prices were projected to stay relatively flat over the longer term due to new supply availability. *See* **Ex. __ (WAG-41C)**; **Ex. __ (WAG-29)** at 138-39.

In addition, PSE's review of actual historical natural gas prices around that time did not cause it to fundamentally question the general range of price forecasts available in the industry. *See, e.g.*, **Ex. __ (WAG-42).** Although PSE recognized that prices had at times spiked or been volatile, they had generally settled back down such that the commodity price risk exposure and potential for market volatility did not seem to justify the premiums demanded for long-term, fixed-price contracts or the reduced flexibility associated with such contracts.

F. PSE's Fuel Supply Management in 2000-01

Q: How did the Company manage its Tenaska and Encogen fuel supply in 2000-01?

A: During that period, which encompassed the tumultuous Western Power Market Crisis, the Company continued to invest significant time and resources on expansion of its market analysis and portfolio analysis, with a focus on risk management. Gas procurement for Tenaska, Encogen, and the balance of PSE's gas-fired generation fleet was a priority objective. PSE monitored, analyzed, evaluated, and attempted to improve its risk management systems and outcomes. Hedging and portfolio management issues were a regular topic of discussion within the Company. Fuel supply risks were among the risks that the Company identified and managed through the systems and personnel described above. *See* **Ex. __ (WAG-36C).**

In addition to continuing spot market and monthly and seasonal hedging transactions, the Company in early January 2000 (after the buyout of the Encogen Cabot contract) hedged 10,000 MMBtu/day on a long-term basis. This quantity represented approximately half of the re-structured gas volume of 21,800 MMBtu/day associated with the Cabot agreement. The price for the hedge was a fixed price beginning at $2.1025/MMBtu in 2000 and rising to $2.6200/MMBtu in 2008. *See* **Ex. __ (WAG-40C)**.

Q: What risk management systems did the Company have in place to manage fuel supply during this time period?

A: In late 1999, the Company purchased a suite of programs that were intended to consolidate risk tracking, electric scheduling and gas scheduling from ALTRA, an energy software developer located in Houston, Texas. The Company implemented the gas scheduling system (GMS) in early 2000. The GMS system tracks the daily trading and long-term physical gas transactions. *See* **Ex. __ (WAG-36C)** at 143.

In addition, PSE further developed its risk management processes, with attention paid to position definition, valuation, risk analysis, strategy development, decision-making, execution of hedges, and operational management. PSE moved increasingly toward managing its resources as a portfolio rather than on a unit by unit basis. *See* **Ex. __ (WAG-36C)** at 122-124, 146-151, 181-186. From June 2000 through August 2001, PSE obtained additional portfolio risk management services from MEGA, including: (1) review of substantive risk positions in the portfolio; (2) development of hedge implementation strategies; (3) advisory services to assist PSE in developing systems; (4) procedures, strategies and tactics for managing its energy portfolio; (5) training of PSE personnel in the identification and management of risk in the portfolio; (6) assistance in the selection and implementation of a computer-based energy trading and risk management system; and (7) assistance in the development of risk management practices and procedures for management of its portfolio.

At the same time, PSE prepared an Energy Supply Hedging and Optimization Procedures Manual (the "Procedures Manual"), which was approved in August 2001. *See* **Ex. __ (WAG-28C)** at ___. The Procedures Manual expanded upon PSE's earlier risk management efforts by introducing additional limits, further defining roles and responsibilities in the energy production area, and providing FAS 133 procedures. The Procedures Manual was further updated in December 2001. *See* **Ex. ___ (WAG-28C)** at 91. PSE also began to develop fundamental analytic capabilities to supplement the various sources of third-party data available in the industry. *See* **Ex. __ (WAG-36C)** at 181.

In July 2001, PSE implemented the ALTRA electric scheduling system (ACES). This system enabled the Company to track daily and long-term physical power transactions and the associated purchase and sale of electric transmission.

Q: Did PSE enhance its in-house risk management capabilities?

A: Yes. During this time period, PSE made organization and staffing changes to support these risk management systems and tools. In the fall of 2000, PSE created a new officer position to lead the risk management and risk control operations (Vice President of Risk Management and Corporate Development). In summer 2001, PSE hired a new Director of Energy Risk Management to help develop new risk analytics. In December 2001, the Company separated the Energy Risk Control and Energy Risk Management functions so they would report to different officers. Energy Risk Control reported to a financial officer, and Energy Risk Management was combined with Power Supply Operations and Gas Supply Operations to report to a new officer, Vice President of Energy Portfolio Management. Ms. Ryan was hired to fill that position.

Q: Did the Company reevaluate with hindsight its management of fuel supply for Tenaska and Encogen in 2000-01?

A: Yes, it did. After gas prices began rising unexpectedly in 2000, PSE conducted a comprehensive review and analysis of its management of the Tenaska and Encogen fuel supply since the buyouts. The "Tenaska Gas Price Situation Business Case Analysis" and "Cabot Gas Price Situation Business Case Analysis" were presented to the RMC on June 9, 2000. *See* **Ex. __ (WAG-36C)** at 152-156, 157-159, respectively. In those analyses, PSE asked itself with hindsight "what should have been done" to manage Tenaska and Encogen fuel supply costs given both information available to PSE at the time *and* information the Company had learned since the prior buyout decisions. PSE also outlined potential courses of action going forward.

Gas and power price increases reached extreme levels in 2000-01 during the Western Power Market Crisis with which the Commission and others in the industry are already familiar. *See, e.g.*, **Ex. __ (WAG-44)** at 44-51. PSE sought to manage its fuel costs through these times in the face of these unprecedented cost pressures and conflicting information about possible solutions to these pressures, such as whether FERC would impose a west-wide power price cap. *See* **Ex. __ (WAG-36C)** at 160-63; **Ex. __ (WAG-45C)**; **Ex. __ (WAG-46C)**.

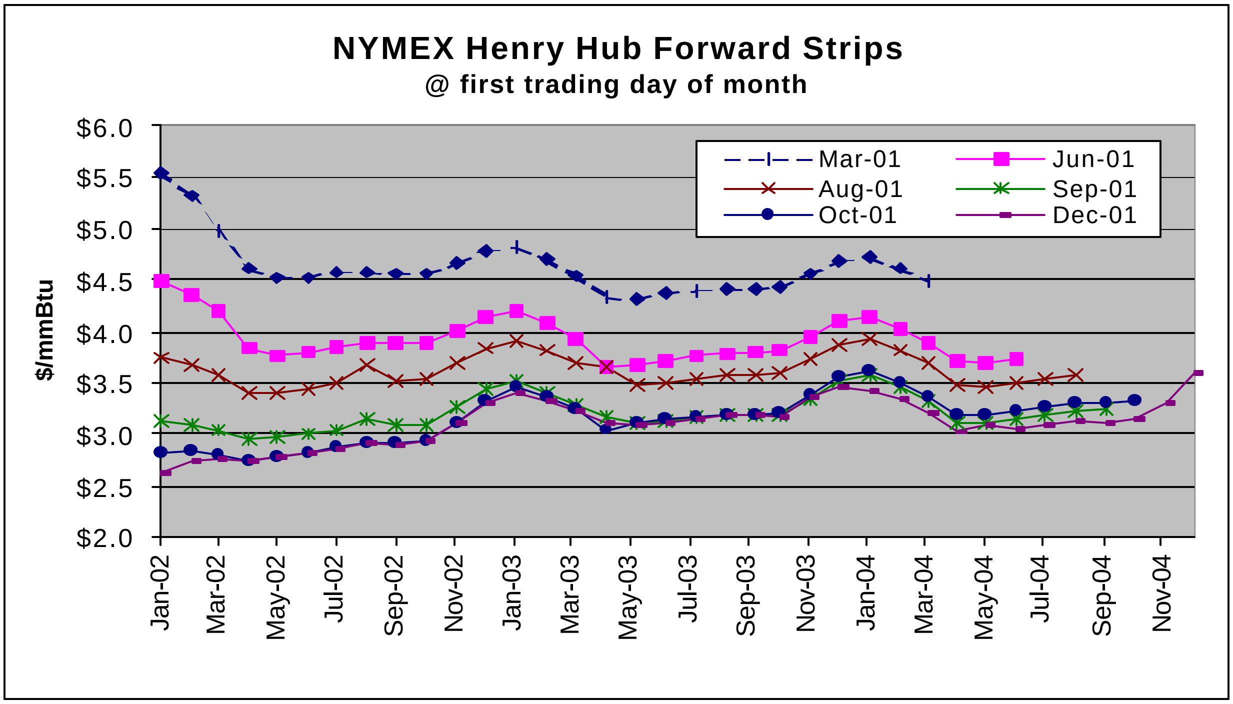
During the Western Power Market Crisis, PSE recognized (again in hindsight) that it would have benefited if it had entered into more long-term fixed-price gas supply contracts at late-1990s prices. (All things considered, PSE fared reasonably well during the power crisis and came out of that period with one of the lowest rate increases of any major utility in the region). Like others in the industry, PSE did not anticipate the sharp increase in natural gas prices that occurred during this time. *See, e.g.*, **Ex. __ (WAG-44)** at 47.

As gas prices started to moderate, PSE decided against purchasing any long-term gas supply because market prices for such contracts were too high relative to fundamental analysis and market signals. In researching this issue, PSE obtained verbal quotes from various counterparties in the market offering long-term fixed price gas. PSE did not view the long-term price quotes it was receiving as attractive relative to fundamental price forecasts such as those from the PIRA Energy Group (which were predicting that prices for natural gas would weaken). *See* **Ex. ___ (WAG-47)**. *See also*, **Ex. __ (WAG-44)** at 52-57.

For example, in June 2001, PSE obtained Q2 through Q4 2002 NYMEX fixed price gas quotes. The NYMEX quotes were significantly higher than either PIRA's forecast or the comparable NYMEX gas price for the same time period (*see* table below).

Fore cast Date	**3/26/01**		**5/24/01**		**6/26/01**		**9/25/01**		**10/20/01**		**12/21/01**	
	PIRA	NYMEX	PIRA	NYMEX	PIRA	NYMEX	PIRA	NYMEX	PIRA	NYMEX	PIRA	NYMEX
Q1	$4.37	$5.38	$3.73	$4.63	$2.80	$4.05	$2.20	$2.83	$2.78	$3.23	$2.70	$3.28
Q2	$3.63	$4.49	$3.60	$4.13	$2.80	$3.49	$2.30	$2.77	$2.60	$3.13	$2.74	$3.06
Q3	$3.60	$4.48	$3.70	$4.21	$2.80	$3.58	$2.57	$2.89	$2.60	$3.22	$2.89	$3.15
Q4	$3.70	$4.56	$3.93	$4.38	$2.90	$3.77	$2.73	$3.09	$2.80	$3.44	$3.09	$3.34
Source: PIRA US Market Forecast												

Moreover, forward market price signals did not support making long-term commitments. Gas prices in the forward markets began to drop after the winter of 2000/01. The graph below shows the historical trend starting in March of 2001 for the gas futures on the NYMEX market. PSE reviewed these forward markets for potential opportunities and recognized that the market was adjusting downward from the recent historical highs it had seen. Because the NYMEX market is a strong indicator of prices for gas at the Sumas market, PSE believed that Sumas forward prices would also weaken. Furthermore, the market was becoming less backwardated (meaning that near-term prices were falling more rapidly, but were still higher, than longer-term prices). Forward prices for January 2002 dropped by $2.90/MMBtu, but dropped by only $1.40/MMBtu for January 2003 which created a situation where the short-term spot prices were less than forward prices. Thus, quotes for long-term fixed price gas appeared to carry a large premium over the short-term spot market.



Finally, additional analysis that PSE performed at the time showed that prices were well above historical averages. *See* **Ex. __ (WAG-36C)** at 221-225.

The on-going reductions to long term prices, the premium that long-term prices carried over short-term prices, and fundamental forecasts of prices below the quoted forward prices provided strong signals to hold off purchasing long-term gas during 2001. PSE sought to manage its portfolio through continued use of shorter-term hedging tools with the expectation that prices would moderate in the longer term.

Q: Did PSE consider locking in long-term gas supply contracts after prices moderated from the peaks seen during the Western Power Market Crisis?

A: Yes. The Western Power Market Crisis marked a paradigm shift in how the Company and others in the industry viewed what had been the prevailing march toward increasing use of wholesale markets to serve core load. As I discussed in my direct testimony, the Western Power Market Crisis showed that a utility that relied too heavily upon the short-term and spot energy markets as sources for energy supplies could face severe and potentially devastating consequences. *See* **Ex. ___ (WAG-1T)** at __. Therefore, PSE re-examined its load-resource balance, market assumptions, exposure to market-driven power price risk, emphasis on optimization and hedging strategies, and the status of its energy generation portfolio in light of the knowledge that PSE obtained during and after the Western Power Market Crisis.

Q: Why didn't PSE purchase 50,000 MMBtu/day for Tenaska for 2003-2011 as recommended in the RMC presentation dated December 13, 2001 that Mr. Schoenbeck describes? (*See* Ex. ___ (DWS-1T) at 29)

A: The RMC materials that Mr. Schoenbeck references are provided in **Ex. __ (WAG-36C)** at 248-258. At the same RMC meeting, a recommendation was made to purchase 10,000 MMBtu/day from 2003 to 2008 for the Encogen plant. As those materials show, the strategy recommendation set a target price for executing those hedges of $2.484/MMBtu for the first year escalating to $3.306/MMBtu in 2011 (for Tenaska) and $2.661/MMBtu escalating to $3.062/MMBtu for Encogen.

Such recommendations were made and approved in this case and several other times, but traders were then unable to find opportunities to lock in a long term price within the target limits. Although recommendations were grounded in a range based on market quotes, they were not typically executable quotes, and the market could and sometimes did rise quickly during that time period such that long-term deals could not be locked in within the RMC-approved price range. *See, e.g.,* **Ex. __ (WAG-36C)** at 170, 191, 199-200, 207; **Ex. __ (WAG-46C)**.

Q: Please state your conclusions with respect to the issues you discussed.

A: I conclude that, during the time period from 1997 through 2002, PSE appropriately managed its fuel supply activities and costs for Tenaska and Encogen through times of significant industry change and market upheaval and crisis.

IV. THE COMMISSION SHOULD ADOPT PSE'S GAS PRICING METHODOLOGY AND PROPOSED GAS PRICE.

Q: What is the purpose of this section of your rebuttal testimony?

A: ICNU's witness, Mr. Schoenbeck, questions the natural gas prices that should be used in updating power costs for the 2004 PCORC Baseline Rate. He proposes that the Commission employ an output from a California planning model, rather than the market-based pricing methodology that PSE presented in this proceeding and in numerous other Commission proceedings. Only ICNU advocates the use of a planning-model based approach.

For a number of reasons, the Commission should not follow ICNU's approach. The Commission should instead continue using the market-based pricing methodology that has been used in prior PSE rate proceedings.

A. PSE's Methodology is a Recognized and Appropriate Approach To Forecast Gas Prices

Q: Please describe the approach that PSE used to forecast natural gas prices.

A: PSE relied upon forward market prices in order to project natural gas prices for the 2004 PCORC Baseline Rate in this PCORC proceeding. PSE used an average of forward market prices that was published over a 10-day consecutive period ending

September 18, 2003, in preparation for its PCORC filing that it ultimately made on October 24, 2003. We selected the September period because we wanted to file prices that were the most indicative of the then-current forward market.

Q: Please explain how forward market prices for natural gas are derived.

A: These prices for natural gas products are derived from forward monthly prices at the New York Mercantile Exchange ("NYMEX"), which is an exchange-traded market that is the most widely-used and followed market in the natural gas industry. The NYMEX price for natural gas assumes a trading point for deliveries and receipts at the Henry Hub location in Louisiana. Trading prices for natural gas at other locations in North America reflect a basis differential off the Henry Hub pricing point – either a premium or a discount.

Q: How does PSE adjust these gas price forecasts for use in its AURORA model?

A: The AURORA model uses gas price forecasts for several trading hubs in the WECC to estimate the Company's power costs. The Company adjusts NYMEX forward gas prices for Henry Hub by market quotes of the basis differential between the Henry Hub price and the price at the various market points used by AURORA.

Q: Are forward market prices a reasonable input for projecting near-term power prices?

A: Yes. Forward market prices for natural gas are inherently unbiased and not developed by any individual entity. The forward prices are instead determined as a result of market transactions by the multitude of entities who buy and sell energy products for delivery in the future. These market transactions represent the willingness of buyers and sellers to commit to future natural gas transactions at various points in time and prices. The forward prices are therefore an objective measuring tool. The prices that result from these market transactions represent a reasonable input in projecting near-term gas prices and, hence, the Company's near-term power costs.

Q: Has PSE used an average of forward market prices in other proceedings?

A: Yes. As Mr. Story discusses in his rebuttal testimony, the Company used an average of forward market prices in its 2001 general rate case. *See* **Ex. ___ (JHS-10T)** at 5.

PSE has also used an average of forward market prices in its Purchase Gas Adjustment filings ("PGAs") that the Commission has accepted. In one such filing in December 2000 (Docket No. UG-001934), Commission Staff noted: "The increase requested by the Company corresponds to forecasts of natural gas prices produced by major commodity markets (e.g., NYMEX)." I have attached Commission Staff's recommendation in Docket No. UG-001934 as **Ex. ___ (WAG-49)**.

Q: Please compare the 2004 PCORC gas price forecast to the forecast in the 2001 general rate case.

A: Mr. Schoenbeck is correct when he states that the gas prices that PSE projected for the 2004 PCORC Baseline Rate period (April 2004 through March 2005) are higher than the forecasted prices from the 2001 general rate case (for the original rate year ending September 2003). *See* Ex. ___ (DWS-1T) at 13 l. 4-7. However, his testimony ignores an important point: the PCA power cost baseline should reflect current market estimates of gas prices because the PCORC baseline rate should reflect an unbiased estimate of power costs, so that there is an equal likelihood that actual costs will be above or below the baseline.

In this regard, and as shown in **Ex. ___ (WAG-45C)**, the prices projected at the time of the 2001 general rate case and incorporated into the original PCA baseline rate were much lower than the actual prices experienced during the 2003 PCA true-up period. PSE's methodology is not designed to (or capable of) "tilting the scales" in PSE's favor in setting a power cost baseline for the PCA mechanism.

B. PSE Does Not Agree with ICNU's Criticisms About PSE's Methodology

Q: Are forward market prices "flawed"?

A: No. As I discussed earlier, the NYMEX prices are based upon a multitude of transactions between willing buyers and willing sellers in the energy markets. I do not see how prices that are established in these markets can be characterized as "flawed."

Q: Does it matter that NYMEX trading volumes during the 2004 PCORC rate year are not as high as during earlier months of the NYMEX strip?

A: No. There are over 40,000 transactions that fall throughout the 2004 PCORC Baseline Rate period; therefore, the NYMEX market represents an actively-traded market for this period. Further, and in addition to NYMEX transactions, there are a large number of Over-the-Counter ("OTC") transactions that occur outside of the NYMEX. The entities that enter into these transactions have the alternative of buying or selling through the NYMEX, as well as arbitraging transactions between the OTC market and the NYMEX. Thus, if the NYMEX prices were out of step, they would quickly be disciplined by the availability of the OTC market.

Q: Should PSE's baseline power cost rate reflect Mr. Schoenbeck's "normalized" gas prices rather than forward market prices?

A: No. For the reasons that I have discussed, PSE's gas price methodology produces an unbiased estimate of future gas prices. In this proceeding, where the objective is to set an expected power cost baseline rate that will be trued up later in an annual PCA true-up proceeding, it makes sense to set that rate using the best-available current market data – forward market prices.

C. ICNU's Proposed Approach Should Not Be Adopted

Q: What approach does ICNU propose to project gas prices?

A: Mr. Schoenbeck recommends that the Commission adopt the output from a long-term price projection model that the California Energy Commission ("CEC") developed. He does not discuss the model's methodology or assumptions. Nor does Mr. Schoenbeck state why the Commission should use the CEC's model in this 2004 PCORC proceeding, other than the fact that he has "been aware of the CEC tool for many years." *See* Ex. ___ (DWS-1T) at 20 l. 3.

Q: Do you have specific comments regarding ICNU's proposed approach?

A: Yes. Mr. Schoenbeck erroneously asserts that the CEC developed and approved a $3.61/MMBtu price as a forecasted price at Sumas. *See* Ex. ___ (DWS-1T) at 19 l. 4-5 (reference to "CEC Sumas price projection"). That figure does not appear in the December Report that he references. The figure he mentions appears to represent one output from the CEC's model using unknown assumptions – not a specific price that the CEC has projected at Sumas. Mr. Schoenbeck's testimony does not list or describe any of the assumptions that he used in running the CEC's model. In addition, the $3.61/MMBtu figure does not match any current or expected market price at Sumas.

Q: Please summarize your recommendation with respect to gas pricing.

A: I recommend that the Commission approve the forward market price that PSE proposed in its 2004 PCORC filing. The forward market price methodology that the Company employed is a reasonable indicator for the purpose of deriving the Company's next Power Cost rate. While gas prices will be trued up in future annual PCA true-up proceedings, because of the deadbands in PSE's PCA mechanism, it is very important to the Company that gas prices be set as objectively as possible and based on reasonable estimates of future prices rather than on historical prices.

Q: Will you be responding to ICNU concerning PSE's use of its fundamental price forecasting model (KW3000)?

A: No. Ms. Ryan discusses the Company's use of the model in her rebuttal testimony. *See* **Ex. ___ (JMR-11T)** at 7-8, 11-12.

Q: Are you sponsoring any exhibits to your rebuttal testimony?

A: Yes. I am sponsoring the following exhibits which are attached to my testimony:

EXHIBIT LIST

	Description of Exhibit	Exhibit No.
WAG-18T	Rebuttal Testimony of William A. Gaines	
WAG-19	Rebuttal Revision to Ex.___ (WAG-15)	
WAG-20	Rebuttal Revision to Ex.___ (WAG-16)	
WAG-21C	PSE Response to WUTC Staff Data Request 70	
WAG-22C	PSE Response to ICNU Data Request 2.05	
WAG-23C	PSE Response to ICNU Data Request 2.08	
WAG-24	Tenaska/Encogen Fuel Supply Context Timeline	
WAG-25	Transcript of Dec. 10, 1997 Open Meeting	
WAG-26	PSE's Response to Staff Data Request No. 4, Docket No. UE-971619	
WAG-27	PSE Response to WUTC Staff DR 45 (history of risk mgmt)	
WAG-28C	PSE Response to WUTC Staff DR 48 (risk mgmt manuals)	
WAG-29	PSE's 2000-01 Least Cost Plan (excerpts)	
WAG-30	Historical Overview of the Natural Gas and Electric Industry in the 1990s	
WAG-31	Resource mix pie charts (before and after buy outs)	
WAG-32C	PSE's Accounting Petition re Tenaska Buyout – Exhibit E (UE-971619)	
WAG-33C	Gas Commodity Price Forecasts	
WAG-34	Sumas Gas Historical Prices, Market Quotes, and Forecasts as of January 1998	

	Description of Exhibit	Exhibit No.
WAG-35C	Fuel management spreadsheets and analyses (1997-99)	
WAG-36C	Risk Management Committee (RMC) materials (1997-2001) (excerpts)	
WAG-37	BPA Power Subscription Strategy Proposal (Sept. 18, 1998)	
WAG-38	PSE Board Materials regarding Tenaska and Encogen Buyouts	
WAG-39C	Tenaska hedging decisions documents (1998-99)	
WAG-40C	Deal No. CR 0251 (1/6/2000)	
WAG-41C	PIRA Dec. 22, 1999; Natural Gas Briefing Feb/March 2000;	
WAG-42	Daily power and gas prices chart (1996- January 2000)	
WAG-43	*Reserved*	
WAG-44	Relevant trade press (2000-2001) (excerpts)	
WAG-45C	PSE's Responses to Staff DRs 13 and 91-I (UE-011570)	
WAG-46C	PSE's Responses to Staff DR 7 (UE-011570)	
WAG-47	PIRA's US Market Forecast reports, issued on March 26, 2001, May 24, 2001, June 26, 2001 and September 25, 2001	
WAG-48C	PSE's Response to Staff DR 7 (UE-011163)	
WAG-49	Commission Staff's recommendation in Docket No. UG-001934	

Q: Does this conclude your rebuttal testimony?

A: Yes, it does.