EXHIBIT NO. _____ (WAG-1T)
DOCKET NO._____
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. _____

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

OCTOBER 24, 2003

TABLE OF CONTENTS

PUGET SOUND ENERGY, INC.

DIRECT TESTIMONY OF WILLIAM A. GAINES

Q: Please state your name, business address and occupation.

A: My name is William A. Gaines. I am currently employed as Vice President, Engineering & Contracting at Puget Sound Energy, Inc. ("PSE" or the "Company"). Previously, I served as Vice President, Energy Supply at PSE from February 1997 until October 2003, when I assumed my current position. My business address is 10885 NE 4th Street, Bellevue, Washington 98004.

Q: What are your educational background and professional work experience?

A: My educational background and professional work experience are described in **Ex. ____ (WAG-2)**.

Q: Have you appeared as a witness before this Commission or in other regulatory proceedings?

A: Yes, I have appeared before this Commission numerous times on behalf of PSE.

I. PURPOSE AND CONCLUSIONS OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to: (1) provide an overview of PSE's application to change the Power Cost Adjustment ("PCA") rate; (2) describe the early planning processes and analyses that gave rise to PSE's recent generation acquisition decision and rate case filing; (3) describe the PCA Mechanism and the power cost only rate process ("PCORC"); and (4) discuss the management of PSE's electric supply portfolio and identify specific developments that have driven changes to PSE's power costs since the PCA Mechanism was implemented.

Q: Please summarize the conclusions in your testimony.

A: Major upheavals, volatility and uncertainty in the wholesale energy markets, an approaching deficit in generation resources, and enhanced internal planning and risk management capability have fundamentally influenced PSE's approach to maintaining adequate energy and capacity resources to meet its load obligations and managing risk. Two important objectives govern PSE's Five-Year Strategic Plan: "(1) Focus on regulated utility business" and "(2) Add generation and delivery infrastructure to meet customer need." *See* **Ex. ____ (WAG-3).** After considerable analyses and public input, PSE has established a detailed and balanced portfolio approach to meet its customer load obligations and risk management objectives. The Least Cost Plan that PSE filed in April 2003, and the August 2003 Update to the Least Cost Plan (collectively, the "2003 Least Cost Plan"), describe how PSE intends to meet its load obligations through aggressive conservation, a commitment to renewable generation resources, and utilization of efficient and diverse power generation sources.

Consistent with the Strategic Plan and the 2003 Least Cost Plan, PSE has made commitments to conservation and renewable resources and to the acquisition of a new, highly-efficient generation resource in order to meet its load obligations. The resource acquisition and changes in PSE's existing power costs necessitate the present application to true up the PCA Rate.

II. OVERVIEW OF PSE'S APPLICATION TO CHANGE THE PCA RATE

Q: Please summarize the testimony of the other witnesses who appear for PSE.

A: In addition to myself, the following witnesses present direct testimony on PSE's behalf:

Mr. Charles Black, who led development of the 2003 Least Cost Plan, describes the Company's least cost planning process, analyses, and results. Mr. Black discusses

PSE's current need for new electric resources (which results largely from the expiration of certain long-term power contracts in the Company's supply portfolio), as well as the resource planning standard that the Company decided to adopt. In the least cost planning process, the Company used various analytical tools and professional judgment to adopt a balanced resource strategy that includes a diversified mix of new electric resources (conservation resources, renewable resources, and thermal resources) to be acquired in stages through the 20-year planning period.

Ms. Julia Ryan, PSE's Vice President of Energy Portfolio Management, describes PSE's energy risk management activities. She then reviews the current status of the wholesale power markets in the Western region. She concludes her testimony by describing why the Frederickson 1 plant in which PSE has agreed to acquire an ownership interest will help the Company meet its load obligations; offer several economic and operational benefits; and enable the Company to better manage risk.

Mr. Eric Markell, PSE's Senior Vice President of Energy Resources, describes: (1) the state of the market for energy generation facilities; (2) PSE's multi-faceted resource acquisition process and negotiations over the last 15 months; and (3) the Company's acquisition of a 125 MW (potentially increasing to 137.5 MW) share of, and a 49.85% ownership interest in, EPCOR's Frederickson 1 combined cycle-combustion turbine ("CCCT") project.

Finally, **Mr. John Story**, PSE's Director of Cost and Regulation, describes: (1) adjustments to PSE's power supply costs that have prompted PSE to seek the proposed Power Cost Rate; (2) the rate impact of adding a new resource to PSE's power supply portfolio; (3) the calculation of PSE's new Power Cost Rate, which accounts for the addition of new power cost resources to PSE's power supply portfolio, updates expenses to account for current costs, and corrects the allocation for production-related

costs; and (4) the change to customer tariffs attributable to the adjustments to the Power Cost Rate.

III. DEVELOPMENTS THAT INFLUENCED PSE'S RESOURCE STRATEGY

Q: Please describe the approach that PSE took to load-resource management before the Western Power Market Crisis began in the summer of 2000.

A: In the 1990s, the electric power industry in the United States began a significant economic and regulatory shift -- from traditional vertically integrated utilities (which owned and controlled all aspects of generation, transmission and distribution necessary to serve customers) to an evolving wholesale electric power market in which independent, loosely-regulated power producers were considered to be the most efficient developers of generation resources and marketers of electric power, and regulated transmission and distribution utilities were considered vital only for the delivery of such power on an "open access" basis. Prior to the passage and implementation of the National Energy Policy Act of 1992 ("EPAct"), wholesale electricity markets were essentially the exclusive domain of electric utilities that owned and operated generation and transmission facilities.

Beginning in 1996, the Federal Energy Regulatory Commission ("FERC") implemented EPAct through a series of orders, most notably Order No. 888, that were designed to encourage the creation of competitive wholesale generation markets through non-discriminatory open access to the transmission systems built and owned by integrated utilities. Some states, such as California and Montana, decided to go one step further towards deregulation by implementing retail competition.

While Washington State did not go so far as to embrace retail access, PSE's 2000-2001 Least Cost Plan, which was filed with the Commission in December 1999, reflected the industry's prevailing wisdom at the time: that Federal policy initiatives would push

utilities toward increasing reliance on competitive commodity markets to meet their power supply needs. At the time the 2000-2001 Least Cost Plan was filed, and as documented in that Plan, it appeared 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. Given the uncertainty associated with evolving policy, the Company considered such long-term fixed-cost generation assets to be potentially more expensive and more restrictive than short-term contracts, the spot market, and new hedging instruments that were becoming available in the evolving power markets.

Further, the Company's approach at the time reflected its near-term position: a relative load-resource balance. This put PSE in a position to monitor developments in the industry before long-term resource acquisition decisions would need to be made.

Q: How did PSE manage energy market risk during this period?

A: As PSE increased its reliance on the wholesale power markets, it realized that it needed to develop stronger risk analysis and management tools to manage its energy supply portfolio. PSE's power supply/demand balance varies hourly, daily, and seasonally based on a variety of factors such as temperature-induced variations in customer demand, the effects of varying streamflow on hydroelectric generation, and forced outage of owned and contracted generating units. Due to these fluctuations, PSE must participate in the wholesale markets to sell surplus energy or purchase needed energy – which requires the Company to assess and manage the risks associated with these market transactions.

PSE began to manage such risk and to participate more actively in the evolving electric power and transmission markets, as analytical tools and a variety of hedging

instruments became available. PSE established a Risk Management Committee ("RMC") -- composed of senior PSE officers -- to oversee the development of the Company's risk management strategies and the preparation of an Energy Supply Procedures Manual.

PSE also engaged Merchant Group of the Americas, Inc. ("MEGA"), a company with experience in energy risk control and management systems infrastructure, to assist PSE in developing its energy risk control and management systems. Ms. Ryan, the lead consultant for MEGA, assisted PSE with these activities. PSE then hired Ms. Ryan in late 2001 to manage the Company's short-term and medium-term (up to two year) energy portfolio and risk. Ms. Ryan describes in her testimony how the Company performs its risk management activities. *See* Testimony of Julia M. Ryan, **Ex. ____ (JMR-1T)** at 6-10. She also sponsors the Company's current Energy Supply Procedures Manual. *See* **Ex. ____ (JMR-3C).**

Q: How did the Western Power Market Crisis affect PSE's generation strategy?

A: The Western Power Market Crisis drove energy prices to unprecedented heights; compromised the financial condition of many utilities and other energy companies; and undermined the ability of energy companies to finance and develop merchant energy projects. The Western Power Market Crisis also demonstrated 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. The Western Power Market Crisis made PSE aware of the need to engage in active short-term resource portfolio management and rigorous long-term resource planning. Ultimately, the Western Power Market Crisis was an important factor that led PSE to re-examine its load-resource balance, market assumptions, appetite for market-driven power price risk, emphasis on optimization and hedging strategies, and the status of its energy generation portfolio.

IV. PSE ADOPTED A RESOURCE PLANNING INITIATIVE

Q: Please describe the origin of PSE's recent resource planning initiative.

A: In October 2001, PSE appointed a new Director of Load-Resource Strategies and brought together both existing and new planning staff to assess the Company's existing resources and determine what long-term generation needs would be needed to meet the Company's load requirements. The initial focus of these efforts was to verify the shortfall in generation resources predicted for 2004 and beyond due to the expiration of certain long-term power contracts.

Q: Where did this analysis begin?

A: The load-resource strategies team performed several initial tasks:

- **First**, the team reviewed PSE's load forecast. Working with the Company's load forecasting group, the team made certain new adjustments to the load forecasts, such as segregation of the former Schedule 48 customers' loads; downward adjustments to PSE's projections of Internet Service Provider ("ISP") loads; reductions in loads that reflected savings from conservation programs; and the projected slowing in population and economic growth. Using load forecast modeling, the team arrived at projected average annual sales through 2009.
- **Second**, the team reconfirmed the inventory of PSE's owned resources and estimated the generation potential for each resource. This assessment included a review of PSE's coal, combustion turbine, and hydro resources and the most recent hydro data for the PSE-owned and Mid Columbia-purchased hydroelectric production projects.
- **Third**, the team assembled and reviewed all of PSE's long-term power purchase contracts and exchange agreements. For each contract, the team reviewed the

operating parameters and limits that determine the flexibility of each supply contract.

- **Finally**, and working from these data, the team assembled a resource-by-resource 10-year forecast of both the energy and capacity available in PSE's then-existing generation portfolio.

Q: What did the load-resource strategies team find?

A: The team reconfirmed and documented that, over the next decade, PSE would experience a significant loss of contracted generation resources. The expiring contracted resources meant a loss of 688 MW of capacity and 264 aMW of energy from 2002 to 2010. *See PSE's Loads and Resources 2002-2010* (Blue Book) (February 2002) at 6, **Ex. ____ (WAG-4)**; *Overview of PSE Loads and Resources 2002-2010* (August 26, 2002) at 10, **Ex. ____ (WAG-5)**. The load-resource strategies team further found that PSE would be in deficit on an energy basis over the period 2003 – 2010, if PSE's 588 MW of single-cycle gas and oil-fired combustion turbines ("SCCTs") are not included. These SCCTs were installed primarily for peaking purposes, are typically not economically operable relative to the market price of power, and are not considered baseload resources for purposes of long-term resource planning.

Q: Did the load-resource strategies team identify and estimate expected resource deficits?

A: Yes. The team identified the load-resource balance for the years from 2002 to 2010 in low, average, and high hydro years and with and without the SCCTs. From these data, the team estimated PSE's yearly deficits through 2010. *See* **Ex. ____ (WAG-4)** at 8-23; **Ex. ____ (WAG-5)** at 13-28.

Q: Did the load-resource strategies team identify any possible ways to meet these deficits?

A: Yes. The team made significant efforts to identify possible generation projects that could replace the expiring contracts. The team met with over 30 project developers and gathered information on over 50 proposed and existing energy generation plants in the Pacific Northwest region. The team inventoried the type of project, its installed capacity, peak capacity, heat rate, cost, location, and other pertinent information on each project. The team assessed both power purchase agreement ("PPA") and asset ownership opportunities. *See, e.g.*, **Ex. ____ (WAG-4)** at 30-38; **Ex. ____ (WAG-5)** at 47-53.

Q: Did PSE investigate whether it could renew the expiring long-term contracts?

A: Yes. Through discussions with the contract counterparties and an assessment of current market conditions, PSE determined that the expiring contracts (most of which were 10-15 years old) could not or should not be renewed or extended on the same terms and conditions.

Q: Did PSE analyze associated transmission issues?

A: Yes. In assessing the development or purchase of new resources, the load-resource strategies team analyzed the current system transmission constraints and the unknown congestion management design of proposed RTO-West. Based upon numerous system impact studies, the team identified constraints upon imports of power into the Puget Sound area from the North (Whatcom/Skagit Counties), East (west of Hatwai cut plane), and South (Oregon), and analyzed the magnitude and costs of dealing with these constraints. *See* **Ex. ____ (WAG-4)**, at 24-29; **Ex. ____ (WAG-5)** at 36-41.

Q: Did PSE investigate any self-build options?

A: Yes. In addition to looking at the existing and proposed generation projects throughout the Northwest and possible upgrades to PSE's existing generation facilities, the load-resource strategies team identified possible "greenfield" sites at which PSE could "build and own" new generation facilities. *See, e.g.*, **Ex. ____ (WAG-4)** at 31; **Ex. ____ (WAG-5)** at 45-46. By the spring of 2002, the team had identified over 25 sites that could be considered for the development of new generation within or near PSE's service territory and transmission system. The team then gathered basic information for each site, analyzed the potential for integration into PSE's transmission system, and reviewed the site's proximity to fuel sources. The team also assessed the types, costs, and reliability of various makes of generation equipment and attendant water, sewer, and other requirements necessary for new project development.

PSE then engaged the firm of Tenaska, Inc. ("Tenaska") to assist PSE in the screening and evaluation of the potential self-build sites. Tenaska has extensive experience developing new electric generation facilities, including siting, permitting, design, major equipment procurement, and construction management for over 9,000 MW of project capability.

Q: Did PSE assess regional efforts to build generation and the availability of long-term market purchases of power?

A: Yes. Because PSE operates as part of the Pacific Northwest power system, PSE's load-resource strategies team gathered information on whether the region as a whole was long or short on generation resources. This information was important in determining whether PSE could safely assume that surplus power would be available for purchase in the Pacific Northwest power markets. PSE found that, according to BPA's White Book (issued in March of 2002), PNUCC's Northwest Regional Forecast (NRF), and the Northwest Power Planning Council's analyses, the Pacific Northwest

region as a whole would be in a significant power supply deficit from 2002 to 2011, even with the addition of then-proposed new merchant plants. *See* **Ex. ____ (WAG-5)** at 31-34; *see also Regional Load-Resources Balance*, **Ex. ____ (CJB-30).**

Q: What actions did PSE take as a result of this assessment by the load-resource strategies team?

A: The information that the team developed provided the impetus for three important developments: (1) the formation of PSE's Energy Resources Committee; (2) the expansion and enhancement of PSE's least cost planning effort; and (3) the investigation and analysis of different resource opportunities. I will discuss each of these developments in turn.

Q: Please describe the formation of the Energy Resources Committee.

A: PSE formed an Energy Resources Committee ("ERC") in April 2002, composed of key officers and directors. The ERC was established to guide PSE's long-term resource development and acquisition strategies and to coordinate the Company's other long-term resource-related efforts. The ERC was also charged with overseeing the development of the LCP.

Q: Was the ERC aware of the Commission's regulatory standards and expectations?

A: Yes. In the Fourth Supplemental Order in Cause No. U-83-54 dated September 28, 1984, the Commission stated a prudence standard related to resource acquisitions. This standard was reaffirmed in the Commission's Eleventh Supplemental Order in Docket UE-920433 dated September 21, 1993, and again in the Commission's Nineteenth Supplemental Order in the same docket dated September 27, 1994. For example, the Fourth Supplemental Order in Cause No. U-83-54 stated at p. 32:

> In evaluating prudency it is generally conceded that one cannot use the advantage of hindsight. The test this Commission applies to measure prudence is what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures.

PSE has been mindful of the Commission's prudence standard throughout the resource acquisition and planning activities that the Company has recently conducted. *See, e.g., Memorandum to the ERC regarding WUTC Prudence Standard* (May 27, 2002), **Ex. ____ (WAG-6)**. In all of its long-term resource-related activities, PSE has analyzed and re-evaluated its resource decisions and prepared contemporaneous documentation to support those decisions.

Q: Please describe how PSE expanded and enhanced its least cost planning effort.

A: PSE began a year-long effort to greatly expand and enhance its least cost planning process. This effort included extensive analysis and active involvement with the Commission Staff, Public Counsel, consumer advocates, conservation and renewable resource advocates, and many others. As Mr. Black discusses in his testimony, PSE engaged in a robust analytical process to determine its long-term resource needs and to plan how best to meet those needs. *See* Testimony of Charles J. Black, **Ex. ____ (CJB-1T).** The least cost planning process verified PSE's significant need for the addition of new electric generation resources. It also led to development of a resource planning standard and a balanced electric resource portfolio strategy (consisting of conservation, renewable resources, and thermal resources) that meets customer needs, keeps rates low, and protects against market risks as recently experienced in the region. *See generally, PSE's 2002-2003 Least Cost Plan* (April 30, 2003), **Ex. ____ (CJB-3)**; *August 2003 Update,* **Ex. ____ (CJB-4)** (collectively, **Exs. ____ (CJB-3)** and **____ (CJB-4)** are referred to as the "2003 LCP" or the "2003 Least Cost Plan").

Q: Please summarize the Company's investigation of resource opportunities.

A: PSE has investigated and analyzed different resource opportunities in coordination with, and as guided by, the least cost planning process. The Company hired a new vice president, Mr. Eric Markell, to lead the resource development and acquisition efforts. PSE issued requests for competitive proposals for built and planned generation assets, and for power purchase arrangements. *See* Testimony of Eric M. Markell, **Ex. ____ (EMM-1T)** at 17, 24. PSE then analyzed different assets and proposed PPAs and investigated PSE's self-build options. After reducing the list of candidates, PSE performed due diligence and negotiated terms and conditions for the short-listed candidates. This process led to an agreement to purchase roughly half of EPCOR's Frederickson 1 combined-cycle combustion turbine project, with a current total capacity of approximately 250 MW. (PSE's share of the project will increase to approximately 137.5 MW when certain duct-firing equipment is installed next year.) *See* **Ex. ____ (EMM-1T)** at 49-50. While this acquisition does not fully satisfy PSE's need for additional generation resources, even when combined with PSE's investment in conservation and commitment to renewable energy sources, it represents a significant first step to ensuring that PSE can continue to meet its load obligations in a cost-effective manner.

V. THE PCA MECHANISM AND THE POWER COST-ONLY RATE PROCESS

Q: Were PSE's electric generation resource needs considered in the 2001-02 General Rate Case?

A: Yes. PSE began to identify its long-term energy resource needs and the risks associated with the volatile wholesale energy supply market in its general rate case filed in late 2001. *See WUTC v. Puget Sound Energy, Inc.*, Docket No. UE-011570 and UG-011571 (consolidated). Based upon its then-ongoing review of loads and resources, PSE realized that it would need to add additional resources to make up for loss of supply due to expiring power contracts. *See, e.g.,* Direct Testimony Of William

A. Gaines On Behalf of Puget Sound Energy, Inc. Regarding Power Cost Adjustment ("PCA") Mechanism Settlement, Exhibit No. 532 in Docket No. UE-0011570 at 5 (June 7, 2002).

Q: How was power price volatility dealt with in the resolution of the 2001-02 General Rate Case?

A: In response to significant price volatility, uncertainty in the wholesale energy markets, and PSE's need to add resources to meet its load obligations, the parties who participated in the Power Cost Adjustment Collaborative agreed to a negotiated PCA Mechanism. *See Settlement Terms for the Power Cost Adjustment Mechanism, Exhibit A to the Settlement Stipulation*, **Ex. ____ (WAG-7)**. The PCA Mechanism set forth an annual accounting process for a sharing of costs and benefits between PSE and its customers over four graduated levels (so-called "bands") of power cost variances on the first $120 million of power cost variances, with a $40 million cap on PSE's potential exposure over a 4-year period ending June 30, 2006. On power cost variances over $120 million, the PCA sharing mechanism allocates 99% of costs or benefits to customers and the remaining 1% of costs or benefits to PSE. The key factors that influence the variability of power costs are unpredictable variations in weather, streamflow levels, and changes in the power and gas markets.

Q: How were PSE's resource needs dealt with in the resolution of the 2001-02 General Rate Case?

A: The parties to the PCA Collaborative recognized that timely review of, and cost recovery for, long-term resource acquisitions are essential to an effective resource planning and procurement process. Specifically, the settlement terms (as amended by the Commission) provided for the following single-issue ratemaking process that could be initiated by the Company for the purpose of including newly acquired resources in rates on a timely basis:

8. **Power Cost Only Rate Review:** In addition to the yearly adjustment for power cost variances, there could be a periodic proceeding specific to power costs that would true up the Power Cost Rate to all power costs identified in the Power Cost Rate. The Company can also initiate a power cost only proceeding to add new resources to the Power Cost Rate. In either case, the Company would submit a Power Cost Only Rate filing proposing such changes. This filing shall include testimony and exhibits that include the following:

- Current or updated least cost plan
- Description of the need for additional resources (if applicable)
- Evaluation of alternatives under various scenarios
- Adjustments to the Fixed Rate Component
- Adjustments to the Variable Rate Component
- A calculation of pro forma production cost schedules that are consistent with this docket, including power supply and other adjustments impacting then current production costs.

See **Ex. ____ (WAG-7)** at 5. With some modifications, the Commission approved the PCA Mechanism in its Twelfth Supplemental Order, Docket No. UE-011570 and UG-011571 (consolidated) (June 20, 2002) at 11-15.

Q: Did the settlement address the time for review of a Power Cost Only Rate Case ("PCORC")?

A: Yes. While the Commission itself is not bound to review a PCORC within a particular timeframe, the settling parties committed themselves to an accelerated PCORC process:

> 11. One objective of a new resource proceeding is to have the new Power Cost Rate in effect by the time the new resource would go into service. Upon the receipt of such filing, hearings would be scheduled to review the appropriateness of adjusting the Power Cost Rate and/or adding the new resource costs to the Power Cost rate. These hearings would consider only power costs included within the Power Cost rate. It is contemplated that this review would be completed in four months. Within 30 days following the four month review, the Commission would issue an order determining the appropriateness of all power costs to be included in the Power Cost Rate and the prudence of any new resource (with a term greater than two years) acquisition.

See **Ex. ____ (WAG-7)** at 6. PSE will seek to expedite this proceeding consistent with the settling parties' commitment.

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

A: PSE did not recover its allowed power costs during the first PCA period, *i.e.* the one-year period that began on July 1, 2002 and ended on June 30, 2003. The primary drivers of this underrecovery were: (1) decreased customer load; (2) higher per MWh power costs due to, among other reasons, observed runoff (October 2002 through September 2003) that was only 81% of normal above Grand Coulee (*see* **Ex. ____ (WAG-8)**); and (3) natural gas prices that were $0.88 / mmbtu higher than assumed in the initial PCA baseline rate (*see* **Ex. ____ (WAG-9)**). Although power market prices were on average $0.05 / MWh higher than forecast in the baseline rate, the increase in power market prices was lower in magnitude than the upward changes in gas prices, thus the heat rates during the first PCA period were less than forecast in the PCA settlement. *See* **Ex. ____ (WAG-9)**. This reduced the quantity of generation at PSE's gas-fired generation plants, which in turn reduced the level of secondary sales transactions and increased the level of secondary purchase transactions that PSE made. *See generally* PSE's 2003 PCA Annual Report, Docket No.UE-031389 (filed August 28, 2003).

Q: Do you expect PSE's undercollection to continue during 2003?

A: Yes. We expect the underrecovery to continue during the remaining part of 2003. The future is always uncertain, but in the near term we do expect to see some lingering underrecovery impacts from low precipitation, lower heat rates, and high gas prices. The resulting higher power costs will increase the PCA deferral. We expect the deferral to reach the $40 million PCA cap some time in the fourth quarter of 2003.

Q: Do you expect this undercollection to continue into 2004 and 2005?

A: We expect the undercollection to continue until the PCA baseline is reset. Once the PCA baseline is reset, the PCA balances would be relatively unchanged through the

end of the rate year if actual costs are equivalent to the forecast. However, future power costs can be much higher or lower than even the best forecasts would indicate. The primary drivers of PSE's power costs are described below in Section VI. The new baseline power cost rate proposed in this filing will be set equal to our present forecast of rate year power costs.

VI. COST VOLATILITY DRIVERS IN PSE'S POWER SUPPLY PORTFOLIO

Q: Please describe the drivers of volatility in PSE's power supply costs.

A: PSE's power supply portfolio contains a diverse mix of resources with widely differing operating and cost characteristics. Although there are many complex variables embedded in the portfolio, the four major volume and price drivers of power cost volatility are: (1) streamflow variation affecting the supply of hydroelectric generation; (2) reduced supply due to forced outages; (3) weather uncertainty affecting power usage; and (4) other variations in market power, each of which arises from factors that are beyond PSE's control. I discuss these factors below:

- **Variations in Hydroelectric Supply**. During an average streamflow year, approximately 35% of PSE's electric energy production is from hydroelectric sources. In an average year, PSE's hydroelectric resources provide approximately 7,200,000 MWH of energy (approximately 6,000,000 MWH from long-term purchases from Mid Columbia hydroelectric projects and approximately 1,200,000 MWH from production at PSE-owned Westside hydroelectric resources). This average supply, however, is subject to significant variation depending on weather patterns. Under very dry or very wet conditions, production from these hydro resources can vary from a low of approximately 5,700,000 to a high of approximately 8,700,000 MWH annually. PSE has no control over the effects of weather on streamflow and hydroelectric production. Further, since much of this hydroelectric production is at "run of river" projects with only insignificant

reservoir storage capacity, PSE has little or no control over the timing of the generation. Consequently, streamflow variation can be a major driver of power cost volatility.

During poor streamflow conditions, PSE must acquire replacement power to serve its customer load; during favorable streamflow conditions, PSE must dispose of surplus power to balance and economically optimize its supply portfolio. These balancing transactions are conducted in the wholesale power markets. Because PSE always faces the wholesale market power price at the margin and the market price of power is quite volatile, hydroelectric shortfalls or surpluses can greatly affect the costs PSE must incur for replacement power or the price it can obtain for surplus power.

The above-described hydroelectric supply volatility is a weather related risk that is shaped by precipitation (amount and distribution) and temperature (which affects shape of natural run-off) – and these factors are obviously beyond PSE's reasonable control.

- **Forced outages.** PSE relies on more than 2,000 MW of thermal generating units to help meet its customer loads. These units include approximately 680 MW of large baseload coal generators with low variable operating costs; approximately 700 MW of relatively efficient gas and oil-fired combined cycle combustion turbine cogenerators; and approximately 595 MW of relatively less-efficient, simple-cycle gas and oil-fired combustion turbine generators. Forced outages at any of these units can expose PSE to significant price volatility in its power supply portfolio. Forced outages are typically caused by material or equipment failure, fire, electrical disturbances, or other force majeure events beyond the Company's control. Compared to other utilities, PSE owns, operates, controls, and performs the

maintenance on a very small portion of its baseload thermal generation (most of it is purchased under PPAs from projects that are owned and operated by others), so PSE has relatively little control over the construction and maintenance of the baseload thermal generation supply in its portfolio. (While forced outages at hydroelectric generating projects can limit operational flexibility, they often do not result in the same types of significant reductions in the volume of energy produced as do thermal-unit forced outages. This is because a multiplicity of units is typically available at hydroelectric projects and the fact that there is typically an excess of project hydraulic capacity compared to available streamflow.)

The degree to which a forced outage at any of these thermal generation facilities creates cost volatility in PSE's power supply portfolio depends on the relationship between the variable operating cost of the unit forced out of service and the market price of replacement power over the duration of that unit's outage. For coal units, the cost volatility risk is almost always significant since the variable operating costs of coal plants are typically well below the market price of replacement power due to the existence of long-term coal supply contracts. For the cogeneration and simple-cycle combustion turbine units, this risk can range from insignificant to very significant, depending upon the relationship between the market price of natural gas and the market price of power at the time of the outage.

If forced outages occur, then PSE's costs will depend on the market price of power. As will be discussed below, the market price of power (and thus, the cost to PSE of a forced outage) is directly correlated to variations in the weather – and this is a variable that is beyond PSE's reasonable control.

- **Load/Temperature Uncertainty**. The Pacific Northwest region has a high saturation of electric space heating relative to other areas of the country. As a

result, the level of PSE's retail electric load is closely related to temperature – meaning that PSE's load increases as the weather gets colder.

On a daily basis, PSE's electric load can vary by as much as 1000 MWH for each one-degree change in temperature. The average temperature in PSE's service area for a winter month can be as much as eleven degrees colder or five degrees warmer, and the average temperature for a winter day can vary as much as plus sixteen degrees or minus twenty-nine degrees. The deficiency or surplus of power supply caused by these temperature swings must be purchased or sold in the wholesale power markets, thus exposing PSE to short-term market prices.

In light of the significant electric heating load in PSE's service territory, PSE's cost of load/temperature uncertainty can be significant. As with variations in streamflow variation and PSE's exposure to forced outages, this type of risk is beyond PSE's reasonable control.

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

PSE's costs of purchases and sales on the secondary market are weather-related, because two major drivers of secondary market prices are temperature (market prices are higher during relatively hot and relatively cold weather) and precipitation (e.g., market prices are relatively higher when hydro supply on the West Coast is relatively low). Further, considering that PSE is a very small participant in the

overall Western power market, and is essentially a "price taker," market prices are beyond PSE's reasonable control.

Q: What conclusions should be drawn from this review of cost volatility drivers in PSE's power supply portfolio?

A: Because PSE has little or no control over the major drivers of its power supply costs (and relatively little ability to mitigate them), the PCA risk-sharing mechanism continues to be a key element of PSE's efforts to manage the cost-effective energy resources that are necessary to meet the Company's load obligations and improve its financial integrity. Other key elements to these interests include rigorous long-term planning, as described by Mr. Black in his testimony (**Ex. ____ (CJB-1T)**); active risk management of PSE's short-term energy portfolio, as described by Ms. Ryan in her testimony (**Ex. ____ (JMR-1T)**); and the acquisition of new resources, as described by Mr. Markell in his testimony (**Ex. ____ (EMM-1T)**).

VII. RESETTING THE POWER COST BASELINE

Q: Please summarize this section of your testimony.

A: This section briefly discusses the management of PSE's power supply portfolio and how that portfolio has evolved since the settlement of PSE's last general rate filing and implementation of the PCA Mechanism in early 2002. It then describes the approach that PSE took in preparing the projection of normalized power costs presented in this filing. Finally, this section provides a description of the Aurora production cost model that PSE utilized in making its projections.

A. PSE's Power Supply Portfolio

Q: Please describe the components of PSE's electric supply portfolio.

A: PSE maintains a diverse portfolio of power supply resources. This portfolio includes: (1) long-term contracts for purchases from Mid Columbia hydro projects; (2) PSE's

own hydro projects located in or near PSE's service territory; (3) other long-term purchase and exchange contracts, (4) coal-fired generation from the Colstrip plant; (5) combined-cycle gas and oil-fired generation in PSE's service territory; and (6) simple-cycle gas and oil-fired combustion turbine generation in PSE's service territory. In addition, PSE participates in the wholesale power market to balance its resource portfolio to its loads.

PSE's power supply portfolio contains a diverse mix of resource and fuel types with various cost and operating characteristics. This diversity avoids undue reliance on any one particular type of power source. PSE's mix of resources with different fixed and variable costs allows PSE to respond to the effects of various loads and market supply and cost conditions in order to maximize cost efficiency while meeting its load supply requirements. PSE's power supply portfolio is described in greater detail in **Ex. ____ (WAG-10)**.

Q: Has PSE's power supply portfolio changed since it settled its last general rate filing?

A: Yes. Since 2002, PSE's power supply portfolio has become increasingly deficit, reflecting the expiration of certain long-term supply contracts. PSE has acquired new resources during this period which partially offset the loss of these long-term supply contracts, and has also adjusted and reduced certain other projected electric power costs in an effort to develop a more reliable, cost-effective power supply portfolio. These changes, adjustments and improvements include the following:

- Three of PSE's long-term power supply contracts expired or will expire shortly.
- PSE assumes a retirement of its White River Hydroelectric Project.
- PSE agreed to acquire energy from the Nooksack Hydroelectric Project.

- PSE extended the lease of its Whitehorn 2 & 3 combustion turbine units.
- PSE agreed to acquire a 49.85% interest in the Frederickson 1 Plant.

Q: Please describe the long-term supply contracts that expired or will expire shortly.

A: Following is a brief description of each such contract:

- **Avista**. This contract expired on December 31, 2002. The Avista contract was most recently a 33 MW capacity contract with 24.7 aMW of energy.
- **PacifiCorp**. This contract will expire on October 31, 2003. The PacifiCorp contract is a 200 MW capacity contract with 97 aMW of energy.
- **CSPE**. This contract expired on March 31, 2003. The CSPE contract was most recently a 30 MW capacity contract with 16 aMW of energy. Further, there has been a related increase in PSE's obligation to deliver Canadian Entitlement energy (increase of 32 MW capacity, 18.6 aMW energy).

Q: Please explain PSE's projected retirement of its White River hydroelectric generation project.

A: Construction of PSE's White River project in 1910 predated the Federal Power Act of 1920, under which the Federal Power Commission (now FERC) was given authority to license non-Federal hydroelectric projects. Consistent with a jurisdictional determination in the early 1980s, PSE applied for a FERC license in 1983 for its White River project. In 1997, FERC issued PSE a 50-year license that, in PSE's determination, made the project uneconomic due to the imposition of fishery-related instream flow requirements, significant required capital improvements, and other factors. PSE did not accept this license and appealed FERC's license order in 1998. PSE has been operating the project while the appeal is pending under a series of successive FERC stays. This series of FERC stays expires on January 15, 2004.

Considering the significant public interest in the recreational and other non-power uses and attributes of the project reservoir (Lake Tapps), for the past five years PSE has been participating in a collaborative settlement process intended to improve the economics of the project and the license such that it could be accepted, and to address the needs of all project stakeholders. Despite the innovation and goodwill that have been generated through this collaborative process, it presently appears that the best course of action will be to discontinue hydroelectric generation at the project upon expiration of the FERC stays, and continue to work with stakeholders toward preservation of other project attributes. While PSE presently believes this to be the best course of action, the Company does not expect to have a final resolution of all of the issues surrounding the project until after the conclusion of this proceeding.

Hence, for the purpose of forecasting its PCA-related power costs in this filing, PSE has assumed a retirement of the project and a near-term replacement of its output with purchased power. (Ultimately, the loss of this resource would be factored into PSE's long-term resource planning and acquisition processes.) For consistency in this filing, PSE has also removed the book capital associated with White River from its production ratebase. PSE will petition the Commission for an accounting order in the fourth quarter of this year. This petition will request authorization for the appropriate accounting and ratemaking disposition of this plant.

Q: Please describe the Nooksack power purchase agreement.

A: This contract involves the Nooksack hydroelectric plant. PSE owned the original generating plant at Nooksack; the plant was built in 1906, but was no longer operational due to a fire in the generator in 1997. PSE sold the Nooksack property in 2002 to a buyer who, among other things, planned to rebuild the power plant. As part of the transaction, PSE signed a contract to purchase surplus power output from the project. This is a very small contract, estimated to provide approximately 1.5 aMW of

energy. The price is $29.25 per MWh through 2005, which was based upon 95% of the Mid C forward prices at the time the contract was signed. **Ex. ____ (WAG-11)** includes additional detail on the Nooksack contract.

Q: Please describe the extension of the Whitehorn lease.

A: PSE leased Whitehorn units 2 and 3 in 1981; these units are simple-cycle gas and oil-fired combustion turbines that provide approximately 150 MW of capacity. The primary term of this lease was set to run through July of 2004 and included very favorable lease extension provisions. Given the Company's need for peaking resources as described by Mr. Black in his testimony and in the 2003 LCP, PSE examined the best course of action with regard to the lease extension option. *See* **Ex. ____ (CJB-1T)** at 38-39. We compared the cost of extending the lease to the cost of other resource and market alternatives, and to the option of purchasing the Whitehorn units. Based on this comparison, extension of the Whitehorn lease was clearly economical. Additional information on the lease renewal is provided in **Ex. ____ (WAG-12)**.

Q: Are there any other changes or adjustments to PSE's power supply portfolio costs that you would like to discuss?

A: Yes. Since 1988, PSE has been in the process of obtaining a new FERC license for its Snoqualmie hydroelectric project. The Company submitted a license application in November 1991 which proposed to raise plant capacity from 42 MW to 73 MW, and was based on an additional 1,500 cfs water right. The original long-term license expired in December 1993, and the project has operated under annual licenses since that time. In 1995 PSE submitted a revised and scaled-back license application that raised capacity from 42 MW to 47 MW and did not involve an additional water right. Issuance of the new long term FERC license is anticipated before the end of 2003. It is anticipated that the new FERC license will have a modest effect upon the operation of, and energy production from, the Snoqualmie project. However, over the period 2005 –

2008, various capital improvements will be made which will raise the all-in cost of power from the project. The Company has conducted extensive and ongoing evaluations which show the new project costs to be economic relative to other potential sources of long term power supply. These evaluations are included in **Ex. ____ (WAG-13).**

Considering the imminent issuance of the FERC license, PSE has included as part of the production ratebase associated with the Snoqualmie project the costs that it has expended in obtaining the new license. Costs associated with license-related capital improvements will be included in future filings.

Q: Has the Company presented support for the Encogen cogeneration project purchase and the gas contract restructure for Cabot and Tenaska gas contracts?

A: Yes. At the time that PSE decided to purchase the gas supply contract from Tenaska Gas Co. and restructure the power purchase agreement with Tenaska, PSE performed economic analyses of purchasing the gas supply contract and amending the power supply contract versus maintaining the then status quo. These economic analyses demonstrated the power cost savings anticipated to result from the contract restructuring and were presented to the Commission as Exhibit B to PSE's Accounting Petition in Docket No. UE-971619 (filed November 7, 1997). To the extent that the this matter merits further review, I incorporate by this reference the analyses filed in that docket.

The Company also filed two other accounting petitions with the Commission: (1) regarding the Encogen contract buyout, in Docket No. UE-991498 (filed September 30, 1999); and (2) regarding the Cabot Oil & Gas agreement, which was part of the gas supply for Encogen, in Docket No. UE-991918 (December 8, 1999). The economic analyses for both transactions were provided in their respective filings for the

accounting orders. To the extent that the these matters merit further review, I incorporate by this reference the analyses filed in those dockets

B. Normalized Power Costs

Q: Please describe how PSE projected its normalized pro forma net power costs in this filing.

A: Consistent with prior general rate cases, PSE made adjustments to current test year (the 12 months ending June 30, 2002) power cost data. The effect of these adjustments is to develop projected power costs for the rate year (the 12-month period beginning April 1, 2004). As discussed by Mr. Story in his testimony, the resulting projected power supply costs were then adjusted to test year levels by multiplying by an adjustment factor of 0.98927, which reflects the ratio of test year weather normalized delivered energy loads to rate year weather normalized delivered energy loads.

As has been advocated by Commission Staff, PSE used an hourly dispatch model to project its normalized net power costs for the rate year. PSE used the Aurora model -- a fundamentals-based hourly production cost model -- to develop its model results. Aurora relies upon key factors such as available power supply resources, regional electric demand, natural gas prices and transmission capacity to develop model results, factors that drive resource operations and prices in the electric power market. Aurora uses hourly demand and individual resource operating characteristics in a transmission-constrained, chronological dispatch algorithm for the entire WSCC area. For modeling purposes, the WSCC is divided into thirteen areas and the economic dispatch for each area is determined based on the loads and resources in each area and its transmission interconnection capacity with other areas. Aurora determines an hourly market clearing price for energy through balancing the economic dispatch among all of the areas. A full description of the Aurora model is included as **Ex. ____ (WAG-14)**.

PSE and Aurora's vendor (EPIS) have made a number of extensions and database updates to the model in order to adapt Aurora to produce projected net power costs for the PSE system. These adaptations include:

- **Development of generation data.** These data were developed for Pacific Northwest hydroelectric projects for each of the 40 water years of record prescribed for use by PSE in its forecast of power costs, based on the Northwest Power Pool 2002-2003 Final Regulation. Subsequently, specific generation data were updated for each of the five Mid Columbia hydroelectric projects from which PSE purchases power based on the 2003-2004 Modified Regulation. Generation data for the 40 water years of record for PSE-owned hydroelectric projects were developed based on historical daily streamflows and current plant operating capabilities and operational constraints.
- **Development of additional contract types.** These contract types simulate the cost characteristics of PSE's NUG power purchase contracts.
- **Update to the Aurora WSCC database.** This update includes resources that are projected to come on-line through 2004.
- **Other adaptations.** Data and databases were developed to include PSE's load and resources as a specific "Portfolio" within the Oregon/Washington/Northern Idaho dispatch area. In order to obtain proper model results, it is necessary to define a Portfolio within Aurora that: (1) identifies the specific generating resources to be allocated to the Portfolio; (2) defines the power purchase and sales contracts included in the Portfolio; and (3) provides forecasts of the monthly loads as well as the hourly shape of the loads for the Portfolio.

Since Aurora computes the market clearing price for power based upon the marginal generator in each hour of the dispatch simulation, and that marginal generator is typically gas-fueled, the forecast of natural gas prices is another important input to the

Aurora model. To project natural gas prices for the rate year, PSE adopted an average of the forward market prices for natural gas over a 10-day period ending on September 18, 2003.

Q: What historical streamflow record has PSE used in its "expected value" normalized net power cost projection?

A: PSE has prepared projections of its net power costs using a 40-year streamflow history. In prior orders, the Commission has required electric utilities under its jurisdiction to utilize the 40-year streamflow record over the period 1948-49 through 1987-88 in their power cost projections.

Q: Please quantify PSE's "expected value" normalized net power cost projection.

A: Based upon 40 years of streamflow data, PSE's expected value projected rate year net power costs, including production operations and maintenance ("O&M") expenses, are $755.4 million. Mr. Story adjusts this cost to a test year level per his **Ex. ____ (JHS-4)**. Power costs based on the 40 years of streamflow data were utilized to develop the revenue requirement presented in this case.

Q: How has PSE developed its forecast of Production O&M costs in this filing?

A: PSE has made the following eight adjustments to its test year Production O&M costs:

i) Restated the test year costs for Colstrip coal handling costs which have been reclassified to fuel costs to be in accordance with FERC accounting;

ii) Proformed the Colstrip O&M costs to preliminary test year budget amounts;

iii) Removed the White River O&M costs to reflect retirement of the project for hydroelectric generation purposes;

iv) Proformed the O&M costs of the new Frederickson 1 resource based on forecasted operation and maintenance costs;

v) Restated the test year to normalize O&M for major maintenance for PSE's owned simple-cycle gas and oil-fired combustion turbines based on operating cost studies;

vi) Restated the test year to normalize O&M for PSE's owned Encogen plant based upon operating cost studies;

vii) Proformed the Whitehorn 2 & 3 lease costs to reflect the lower costs of the lease extension; and

viii) Proformed the Fredonia 3 & 4 lease costs to reflect the lower rate year lease costs.

Q: Please describe the principal differences between this forecast of normalized power costs and the forecast of normalized power costs that is presently reflected in PSE's PCA Rate.

A: Please refer to **Ex. ____ (WAG-16),** which shows a comparison of 2002 rate case settlement PCA numbers and the new forecasted normalized power costs.

In terms of supply / demand balance, the new forecast shows an increasing generation supply deficit due to the expiration of certain long-term supply contracts and projected retirement of the White River hydroelectric project. New projections of hydroelectric generation from PSE-owned projects and generation from PSE's Mid Columbia contracts are also lower than the projections reflected in the PCA Rate.

This supply deficit is partially offset by the addition of PSE's new combined-cycle gas-fired resource (the Frederickson 1 plant). Because of lower market heat rates, the new forecast generally reflects lesser amounts of generation from PSE's existing gas and oil-fired resources. Consequently, this forecast projects fewer secondary sales and an increased reliance upon market purchases to meet PSE's loads.

In terms of the impacts on power costs, higher natural gas prices are driving higher costs of generation from PSE's gas and oil-fired resources. In turn, these higher gas prices result in higher power market prices, which increase the cost of the net secondary purchases in the forecast. Escalation in the costs of PSE's existing power purchase contracts are also driving higher power costs in this forecast. These cost increases are partially offset by elimination of the costs of the expired long-term supply contracts.

Altogether, this forecast of power costs, including production O&M, is approximately $50 million higher than what is presently reflected in PSE's baseline PCA Rate.

Q: Are you sponsoring any exhibits to your testimony?

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

EXHIBIT LIST

	Description of Exhibit	Exhibit Number
WAG-1T	Testimony of William A. Gaines	
WAG-2	Description of William A. Gaines's responsibilities, current position, and educational background	
WAG-3	PSE's Five-Year Strategic Plan	
WAG-4	*PSE's Loads and Resources 2002-2010* (Blue Book) (February 2002)	
WAG-5	*Overview of PSE Loads and Resources 2002-2010* (August 26, 2002)	
WAG-6	*Memorandum to the Energy Resources Committee, regarding WUTC Prudence Standard*, May 27, 2002	
WAG-7	*Settlement Terms for the Power Cost Adjustment Mechanism, Exhibit A to the Settlement Stipulation*	
WAG-8	Precipitation/hydrogeneration chart	
WAG-9	Gas prices chart	

	Description of Exhibit	Exhibit Number
WAG-10	Description of PSE's power supply portfolio	
WAG-11	Detail on Nooksack power purchase contract	
WAG-12	Whitehorn 2&3 lease renewal analysis	
WAG-13	Detail on Snoqualmie Hydroelectric Project	
WAG-14	Description of the Aurora model	
WAG-15	PSE's expected value projected rate year net power costs	
WAG-16	Comparison of 2002 rate case settlement PCA numbers and new forecasted normalized power costs	

Q: Does this conclude your testimony?

A: Yes.