EXHIBIT NO. ______ (WAG-4)
DOCKET NO.______________
2001 PSE 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.

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

PUGET SOUND ENERGY, INC.

BACKGROUND – ENERGY SUPPLY ACTIVITIES

I. MONTANA POWER SALES AGREEMENT RESTRUCTURING

In February 1997, PSE and the Montana Power Company (Montana) settled a dispute over delivery provisions in the 94 MW long-term purchase of power from Montana. The settlement resulted in PSE receiving 97 MW of capacity (3 additional MW), a significant reduction in fixed contract costs, elimination of an annual capacity factor restriction, and reductions in Colstrip coal fuel costs.

PSE and Montana entered into a Power Sales Contract dated October 1, 1989, under which Montana provided 94 MW of firm energy at a 75% annual capacity factor to PSE, with the price of such energy tied in part to the cost of coal for Colstrip 4. In 1992, PSE disputed that Montana had met the contract requirement that firm transmission be provided and sought to terminate the Agreement. This action led to litigation and ultimately to a mediated settlement reached on February 21, 1997. Under the Settlement Agreement, PSE would continue to take power from Montana Power under the Power Sales Agreement, but under revised terms. These terms included the following:

(i) provide PSE 3 MW of additional capacity from modifications made to the Unit 4 Steam Turbine for a one time payment of half the capital cost of the modifications;

(ii) reduce the monthly fixed charges to PSE by $6,500 per megawatt through the expiration of the Agreement in 2010; and

(iii) eliminate the 75% capacity factor limit on PSE's right to schedule 97 MW.

It was estimated that the power cost savings resulting from these revised terms would be over $7 million per year.

In addition, PSE, Montana Power and Western Energy agreed to settle a pending dispute regarding the Coal Supply Agreement for Colstrip Units 1&2. PSE further agreed to withdraw from participation in a pending Colstrip Units 3&4 Coal Supply Agreement dispute. Under the settlement, Western Energy agreed to reduce the price of coal under the contracts until the next contract price reopeners. PSE estimated the savings resulting from these coal price changes to be significant.

II. ENCOGEN

The Encogen plant is a natural gas-fired cogeneration plant located in Bellingham, Washington with a capacity of approximately 160 MW. In 1990, PSE entered into a long-term contract with Encogen Northwest, L.P. ("Encogen") to purchase the plant output under the Public Utility Regulatory Policies Act of 1978.

The Company conducted extensive restructuring negotiations with Encogen and the gas suppliers for the project and explored numerous restructuring configurations. In September 1999, the Company signed an Interest Purchase Agreement with Encogen to purchase the Encogen plant. On September 29, 1999, the Company filed a petition with the WUTC requesting an accounting order to address the purchase (Docket No. UE-991498). That petition describes the transaction and the need and rationale for the transaction. On October 27, 1999, the WUTC issued an order approving the Encogen plant purchase accounting treatment (Docket No. UE-991498). In November 1999, the cogeneration deal closed and the Company took over project ownership.

On October 13, 1999, the Company and Cabot Oil & Gas Marketing Corporation ("Cabot") agreed to a gas supply contract buyout, under which the gas supply contract was assigned by Cabot to the Company. On December 8, 1999, the Company filed a petition before the WUTC requesting an accounting order to address the buyout of the Cabot Oil & Gas agreement (Docket No. UE-991918). That petition describes the transaction, and the need and rationale for it. On December 29, 1999, the WUTC issued an order approving the Cabot Oil & Gas buy-out accounting treatment (Docket No. UE-991918).

At the time that PSE decided to purchase the Encogen cogeneration plant, the Company conducted an economic analysis that compared the costs under the then-current Agreement for Firm Power Purchase with the projected costs and benefits of purchasing the plant. The economic analysis was previously provided to the Commission in Docket No. UE-991498 and is included as Exhibit C to the Petition in that docket. That analysis projected a substantial reduction in revenue requirement, on a net present value basis, from the transaction.

At the time that PSE decided to buy out the Cabot gas supply contract, the Company conducted an economic analysis that compared the cost under the contract with forward gas prices. The economic analysis was previously provided to the Commission in Docket No. UE-991918) and is included as Exhibit B to the petition in that docket. That analysis projected the net savings in gas costs as a result of this transaction, based on taking the gas supply price to market, to be significant.

III. TENASKA GAS SUPPLY CONTRACT

Tenaska Washington Partners, L.P. (Tenaska) owns and operates a 245 MW natural gas-fired cogeneration project located adjacent to the Tosco Refinery near Ferndale Washington. The Company and Tenaska entered into a long-term Agreement for Firm Power Purchase dated as of March 20, 1991.

The Company conducted extensive restructuring negotiations with Tenaska and Tenaska Gas Co. (supplier of natural gas to the project). In October 1997, the Company signed a Letter of Intent with Tenaska Gas Co. under which PSE would replace Tenaska Gas Co. as the gas supplier. On November 7, 1997, the Company filed a petition with the Commission requesting accounting treatment of PSE's purchase of the gas supply contract between Tenaska Gas Co. and Tenaska (UE-971619). On December 15, 1997, the Commission issued an order approving the requested accounting treatment (Docket No. UE-971619). On December 23, 1997, the Company and Tenaska Gas Co. executed an Asset Gas Purchase Agreement with Tenaska Gas Co. under which PSE would assume from Tenaska Gas Co. its contract to supply gas to Tenaska.

The Company and Tenaska then entered into an amendment dated January 1, 1998 to the Agreement for Firm Power Purchase that replaced the previous escalating fixed purchase price schedule in that agreement. The new purchase price was the sum of a fixed price component and a natural gas component. The fixed price component is set forth in a schedule in the amendment and is intended to cover all project non-fuel costs (such as debt service, O&M, taxes, etc). The fuel component includes the Company's actual cost of fuel for the month plus the Washington fuel use tax. Therefore, the Company (as the power purchaser) pays a component equal to the fuel costs to Tenaska and, in turn, Tenaska pays the Company (as the fuel provider) for the fuel.

At the time PSE decided to purchase the gas supply contract from Tenaska Gas Co. and restructure the power purchase agreement with Tenaska, the Company performed economic analyses of purchasing the gas supply contract and amending the power supply contract versus maintaining the status quo. These economic analyses demonstrated the power cost savings anticipated to result from the contract restructuring. Such analyses were previously submitted to the Commission in Docket No. UE-971619 as Exhibit B to the accounting petition. (See, e.g., such Exhibit B at line 20.) That analysis projected the power cost savings as a result of this transaction, based on taking the gas supply price to market, to be substantial.

IV. FREDONIA 3 & 4

In January 2001, PSE entered into an agreement with Pratt & Whitney to purchase two 53 MW dual fuel (natural gas/diesel) generators for the expansion of the Fredonia generating plant. Puget financed the acquisition of the two generators through a ten-year lease of such generators and related facilities with BLC Corp. The total lease payments for such generators and facilities in the rate year is $5,457,500. The project was completed and brought on line in July 2001.

At the time PSE decided to purchase the two generators, PSE forecast both short-term and long-term energy and capacity needs. PSE's short run energy needs were greatly impacted by the then-existing Pacific Northwest drought conditions and California's impact on the western power market. PSE's longer-term needs were related to the expiration of long-term contracts scheduled to expire and the expectation of continued regional and service territory load growth.

In the winter of 2000-2001, the Pacific Northwest was experiencing a severe drought (60% of normal run-off). To obtain resources to meet its extreme peak winter loads, the Company took a number of steps, including the purchase of capacity call options and the development of Fredonia 3 and 4. The Fredonia expansion project provides physical generating capacity needed to help meet PSE's extreme winter peak loads. Because market prices and volatility at the time were so high, the cost of capacity call options to meet extreme winter peak loads were very high.

During this time period, it was recognized that there was a critical need for power that could be brought on line quickly. Governor Locke, in his State of the State address and the subsequent package of energy bills in January 2001, explicitly encouraged construction of new generation. The Company received a letter of support from Governor Locke for the Fredonia expansion project, which allowed expedited treatment by the Environmental Protection Agency, the State Department of Ecology, and Northwest Air Pollution Authority.

PSE considered a number of plant alternatives. The Fredonia expansion project provided the highest benefit over the study period. It also met PSE's project criteria of being capable of being brought on-line by summer 2001, the ability to be sited and permitted in a timely manner, a relatively low heat rate, and a 10 minute start capability to qualify as operating reserves.

V. JACKSON PRAIRIE STORAGE PROJECT 1999 EXPANSION

During the period 1997-1999, the owners of the Jackson Prairie Storage Project (including PSE) expanded the capacity of the storage field by approximately 3BCF of working gas capacity and 300 MCF/day of deliverability. The direct cost of this expansion to PSE was about $7 million. Puget participated in this expansion to provide additional service for and to reduce the cost of serving its core natural gas customers

The Jackson Prairie Storage Project, jointly owned by PSE, Avista and Williams Pipeline, is utilized by PSE, in conjunction with other resource options, to meet the winter peak and seasonal load requirements of its core customers as well as provide system balancing. In early 1997, the owners decided to explore the technical and economic feasibility of further increasing the storage capability of Zone 2. Based on these evaluations, the owners approved the expansion of Zone 2 to provide an additional 3BCF of working gas and an additional 300MCF/D of deliverability. As a participant in the expansion, PSE has a 1/3 share of both capacity and deliverability.

The expansion was completed in 1999, on time and under budget. Performance of the reservoir after expansion has met the expectations of the owners when the expansion was authorized.

PSE's analysis showed that there existed a need for additional firm peak day gas deliverability. Based on its projected needs, and the analysis discussed below, PSE exercised its option under the Jackson Prairie ownership agreement to participate at its 1/3 share of the proposed expansion.

The analysis performed by PSE indicated that on a single cycle basis, the expansion of Jackson Prairie, compared to other alternatives, provided the most cost effective and reliable option to meet PSE's system peak day requirements and meet seasonal demands. The other alternatives examined included:

(i) Additional firm pipeline capacity;

(ii) LNG; and

(iii) Propane-Air.

To analyze the relative cost effectiveness of these alternatives, PSE utilized two methodologies, UPLAN-G for scenario analysis and Project Analyzer to forecast the Project NPV, Internal Rate of Return (IRR) and Discounted Payback Period. In both cases, the proposed expansion of the Jackson Prairie Storage Project was the superior alternative.

VI. RESIDENTIAL EXCHANGE BENEFITS FROM BONNEVILLE POWER ADMINISTRATION

PSE signed the PSE-BPA Agreement with Bonneville Power Administration (BPA) in June 2001. The agreement is a settlement of Residential Exchange benefits for the period July 1, 2001 through September 30, 2011, under the 1980 Northwest Electric Power Planning and Conservation Act. The agreement calls for significant federal power benefits for the residential and small farm customers of PSE and is the result of hard work by PSE, the Commission and others to obtain such benefits for the residential and small farm customers of PSE and other investor-owned utilities in the Pacific Northwest.

On December 21, 1998, the Administrator of BPA issued the Subscription Strategy and accompanying Record of Decision. BPA's Subscription Strategy provided a framework for the BPA Rate Case.

The Subscription Strategy also proposed settlements of the residential exchange program with Pacific Northwest investor-owned utilities. The Subscription Strategy proposed a settlement in which the investor-owned utilities were to receive for their residential and small farm customers access to 1,800 average megawatts (aMW) of federal power benefits, of which at least 1,000 aMW would be met with actual BPA power deliveries for the period October 2001 through September 2006 (FY02-06). For the period October 2006 through September 2011 (FY07-11), the Subscription Strategy Proposed offered 2,200 aMW of federal power benefits for the residential and small farm customers of investor-owned utilities.

In April 2000, BPA issued a Supplemental Record of Decision, which increased the level of available residential exchange (RES) benefits and allocated RES benefits among Pacific Northwest investor-owned utilities. The Commission, along with the Idaho Public Utilities Commission, the Montana Public Service Commission and the Public Utility Commission of Oregon, submitted a joint recommendation on the proposed allocation of RES benefits. Specifically, the utility commissions of the four Northwest states wrote a letter to BPA commenting on two items, the total quantity of benefits the investor-owned utilities were receiving and recommending an allocation of the resulting benefits among the investor-owned utilities: (i) the commissions requested an increase in federal power benefits for residential and small farm customers of investor-owned utilities for FY02-06 from 1,800 aMW to 1,900 aMW; and (ii) the commissions recommended an allocation of 700 aMW to PSE for FY02-06 and 648 aMW to PSE for FY07-11.

On October 4, 2000, BPA issued a Record of Decision with respect to Residential Exchange Program Settlement Agreements With Pacific Northwest Investor-Owned Utilities. BPA's proposed Residential Exchange Settlement ("RES Settlement") provides RES benefits to Pacific Northwest investor-owned utilities based on 1,900 aMW for the FY02-06 period and 2,200 aMW for the FY07-11 period.

PSE participated actively in the BPA rate case developing rates for the period FY02-06 to secure federal benefits for its residential and small farm customers.

On February 23, 2001, the Commission and certain other parties to the BPA rate case, including PSE, agreed to and signed a Partial Stipulation and Settlement Agreement. The Partial Stipulation and Settlement Agreement included an agreed-upon dollar amount for the financial portion of the RES Settlement. Pursuant to the Partial Stipulation and Settlement Agreement, the Commission and other parties provided testimony in the BPA rate case in support of the Partial Stipulation and Settlement Agreement.

BPA developed contracts for its preference agency, investor-owned utility and Direct Service Industry (DSI) customers. These contracts were in part jointly developed so that many of the contract provisions were common. Under the investor-owned utilities contracts, the benefits of the 1,900 aMW would be provided as 1,000 aMW of actual firm power and 900 aMW as financial benefits. The financial benefits were to be determined based on the market rate assumption included by BPA in its rate case.

By letter dated August 1, 2000, BPA stated that, under the rates it had filed for FY02-06 period with the Federal Energy Regulatory Commission (FERC), BPA had concluded that its Treasury Payment Probability (TPP) for such period was too low due to wholesale electricity market volatility and increased BPA load projections:

> We have all witnessed the recent price surge. While we cannot define with certainty all the factors that have caused recent short-term price volatility, increases in natural gas prices and west coast supply deficits are driving up BPA's long-term costs of power. . . . And as market prices have increased, there has been a corresponding increase in customers' desire to place load on BPA. It now appears that the firm load placed on BPA may be 1,400 average megawatts higher than anticipated in the rate case, which would require additional major purchases in the market by BPA.

BPA began an amended rate case. PSE continued to play an active role in the BPA rate case, arguing that the residential and small farm customers of the investor-owned utilities should get an equitable share of the federal power benefits. The settlement that emerged from the amended rate case increased the market rate assumption to be used in the calculation of the financial benefits and therefore the value of the contracts to the residential and small farm customers of the investor-owned utilities. The settlement also provided BPA with additional Cost Recovery Adjustment Clause (CRAC) protection.

The first CRAC was to be calculated in June 2001. BPA indicated a 250% rate increase might result. In order to help avoid a large increase, BPA asked customers to reduce the actual power take under their contracts in the first year. Utilities were asked to reduce certain of their first year BPA contract amounts by 10%. Some of the investor-owned utilities were asked to monetize the power component of federal power benefits. PSE and BPA negotiated the PSE-BPA Agreement, which provided for entirely monetary benefits for FY02-06. The estimated benefits of the settlement (financial benefits plus monetized power benefits) for PSE's residential and small farm customers averages about $175,000,000 per year for FY02-06.

On June 4, 2001, PSE filed a copy of the PSE-BPA Agreement requesting Commission approval thereof. In order to implement the PSE-BPA Agreement, PSE also filed revisions to certain of its retail rate schedules and filed a new Schedule 194. The revised and new schedules will pass benefits arising under the PSE-BPA Agreement through to residential and small farm customers of PSE.

By Order Approving Agreement, And Granting Tariff Revisions On Less Than Statutory Notice, dated June 13, 2001, in Docket No. UE-010815, the Commission concluded with respect to the PSE-BPA Agreement as follows:

> When the Commission approved the Partial Stipulation and Settlement Agreement on February 15, 2001, the Commission was joined in such action by the Idaho Public Utilities Commission, the Montana Public Service Commission and the Public Utility Commission of Oregon. The RES Settlement presents issues of significance to the region, and cooperation among interested parties serves the public interest. Such cooperation includes efforts underway between BPA and its customers to secure agreements with BPA to reduce load and thereby reduce upward pressure on BPA's rates.
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> Commission approval of the PSE-BPA Agreement, which is a proposed amended settlement consistent with the Partial Stipulation, is in the public interest. The PSE-BPA Agreement is an appropriate response to BPA's desire to reduce the first-year request from its customers for BPA power by 5% to 10%. The PSE-BPA Agreement will provide benefits to PSE's residential and small-farm customers. The PSE-BPA Agreement is also an important and further step toward maintaining economic stability in the region. PSE, Public Counsel and Commission Staff are commended for their efforts in ensuring reasonable benefits for residential and small-farm customers from BPA.
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> For the foregoing reasons, prompt implementation of the PSE-BPA Agreement, in accordance with its terms, is also in the public interest. Proposed revisions to Schedules 7, 8, 10, 11, 12, 29, 35, 56, 59 and 307 and proposed Schedule 194 are appropriate mechanisms to implement the PSE-BPA Agreement.

In that Order, the Commission approved the PSE-BPA Agreement.

VII. CENTRALIA STEAM ELECTRIC POWERPLANT SALE

In 1997, PacifiCorp, as majority owner and operator of the Centralia Powerplant and owner and operator of the Centralia Coal Mine, approached the other owners to determine their interest in exploring the sale, through competitive auction, of the plant and mine to avoid the cost of adding scrubbers to the powerplant and the risk and cost liability for the reclamation of the mine. All the owners, in order to avoid the divergent management issues of a plant owned by eight different owners, and to resolve uncertainties and costs surrounding the plant and mine, agreed to engage an investment banker to offer the plant and mine through auction. The successful auction resulted in TransAlta purchasing both the plant and mine, for which PSE received $31.8 million for its 7%, 93.8 MW, share of the powerplant. This sale has been described in detail in Docket No. UE-991409, in which the Commission authorized PSE's sale as not being contrary to public interest.

The primary drivers that resulted in the decision by the owners to auction the Centralia Power Plant were:

(i) environmental issues and costs at the Centralia Power Plant;

(ii) final reclamation and mine closure risks and costs at the Centralia Coal Mine; and

(iii) fractionated ownership of the power plant.

Regulatory action to lower the emissions of SO2 and NOx was begun by Southwest Air Pollution Control Authority ("SWAPCA"), in 1993. These actions resulted in a requirement to reduce the emissions of SO2 and NOx from the power plant. These limits were to be met by December 31, 2001, or, if scrubbers were to be used to reduce SO2 emissions, the deadlines were for one unit by December 31, 2001 and the second unit by December 31, 2002. The estimated cost of the emissions control technology required to meet these limits was over $200 million, of which PSE would be required to fund over $14 million for its 7% ownership share. In addition to cost for scrubbers, there continued to be operational risk associated with operating a coal-fired plant in western Washington in that it was and remains uncertain how long it would be possible to continue even these reduced levels of emissions.

Centralia operates under a mine permit that included, by law, a requirement to reclaim land disturbed by mining to its Approximate Original Contour ("AOC") at the end of mine life. Absent approval of a modified mine plan, which may not have occurred if the plant and mine were immediately closed due to plant environmental restrictions, the estimated final reclamation costs ranged up to $486 million, of which PSE would have been obligated to pay its plant ownership share of $34 million. In addition, if the mine immediately closed, additional mine closure costs including paying for mine capital investments, were estimated at approximately $101 million, of which PSE would have been obligated to pay its plant ownership share of over $7 million.

Thus, plant capital requirements for PSE's 93.8 MW share of the plant capacity would have exceeded $14 million with no long-term assurance that the plant would be allowed to operate. Further, there was a risk that should the plant and/or mine be required to shutdown, PSE would have been exposed to over $41 million in mine decommissioning costs plus additional costs associated with power plant decommissioning.

Because of the uncertainties and costs surrounding the continued operation of the power plant and mine, the owners decided to offer the power plant and PacifiCorp decided to offer the Centralia Mine for sale. The purchaser selected, TransAlta, purchased both the power plant and mine for $554 million, of which $454,589,000 was to be paid for the power plant. In the purchase, TransAlta assumed all plant and mine capital and final reclamation costs and all plant environmental liabilities that may arise post closing.

The proposed sale of PSE's 7%, 93.8 MW, share of Centralia was analyzed at the time of the proposed sale utilizing the AURORA model. PSE performed the scenario analysis presented in Docket No. UE-991409, utilizing the AURORA model including low, medium and high market price assumptions. Based on scenario analysis with medium-market price assumptions and related sensitivity analysis (Docket No. UE-991409, Exhibit WAG-4), the analysis projected a significant benefit from the sale.

If PSE, as a 7% owner of the Centralia Power Plant, had refused to participate in the sale, this action would have prevented the sale from happening as constructed and exposed PSE and its ratepayers to the costs and uncertainties discussed above. Because of its minority share, PSE would not have been able to change the structure of the sale.

PSE presented its case requesting authorization of the proposed sale of PSE's share of the Centralia Power Plant and Associated Transmission Facilities in Docket No. UE-991409. On March 6, 2000, the WUTC ruled, subject to certain restrictions, that PSE could sell its ownership share of the Centralia power plant.

[BA013110135]