PUGET SOUND ENERGY

January 9, 2003

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STATE OF WASH. UTIL. AND TRANSP. COMMISSION

HAND DELIVERED

Ms. Carole J. Washburn, Executive Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
Olympia, WA 98504-7250

Re: Docket UE-020963--Puget Sound Energy's Draft Least Cost Plan Filing

Dear Ms. Washburn:

Enclosed, please find an original and eleven copies of Appendix 8.3 for Puget Sound Energy's ("PSE" or "the Company") Draft Least Cost Plan, under the above-referenced docket. This Appendix is referenced on page 13 of Chapter 8—Electric Load-Resource Analysis. Unfortunately, Appendix 8.3 was unintentionally omitted from the final copy that was printed, copied, and filed on December 30, 2003.

The Company would like to clarify one additional note on the format of the Draft Least Cost Plan. At the end of Chapter 8 you will find a document titled "Assessment and Report on Self-Build Generation Alternative for Puget Sound Energy's 2002-2003 Least Cost Plan" prepared by Tenaska, Inc. This is the document referred to on page 1 of Chapter 5—Energy Supply Resources. It was accidentally inserted at the end of Chapter 8 instead of Chapter 5 during the printing process.

The complete corrected version of the Draft Least Cost Plan is now posted on the Company's website and available to the public. We apologize for any inconvenience caused by these errors. Please contact me at (425) 462-3727 if you have any questions or if I can be of any assistance.

Sincerely,

George Pohndorf
Director, Rates and Regulation

Enclosures

www.navigantconsulting.com

Modeling Process Overview

December, 2002

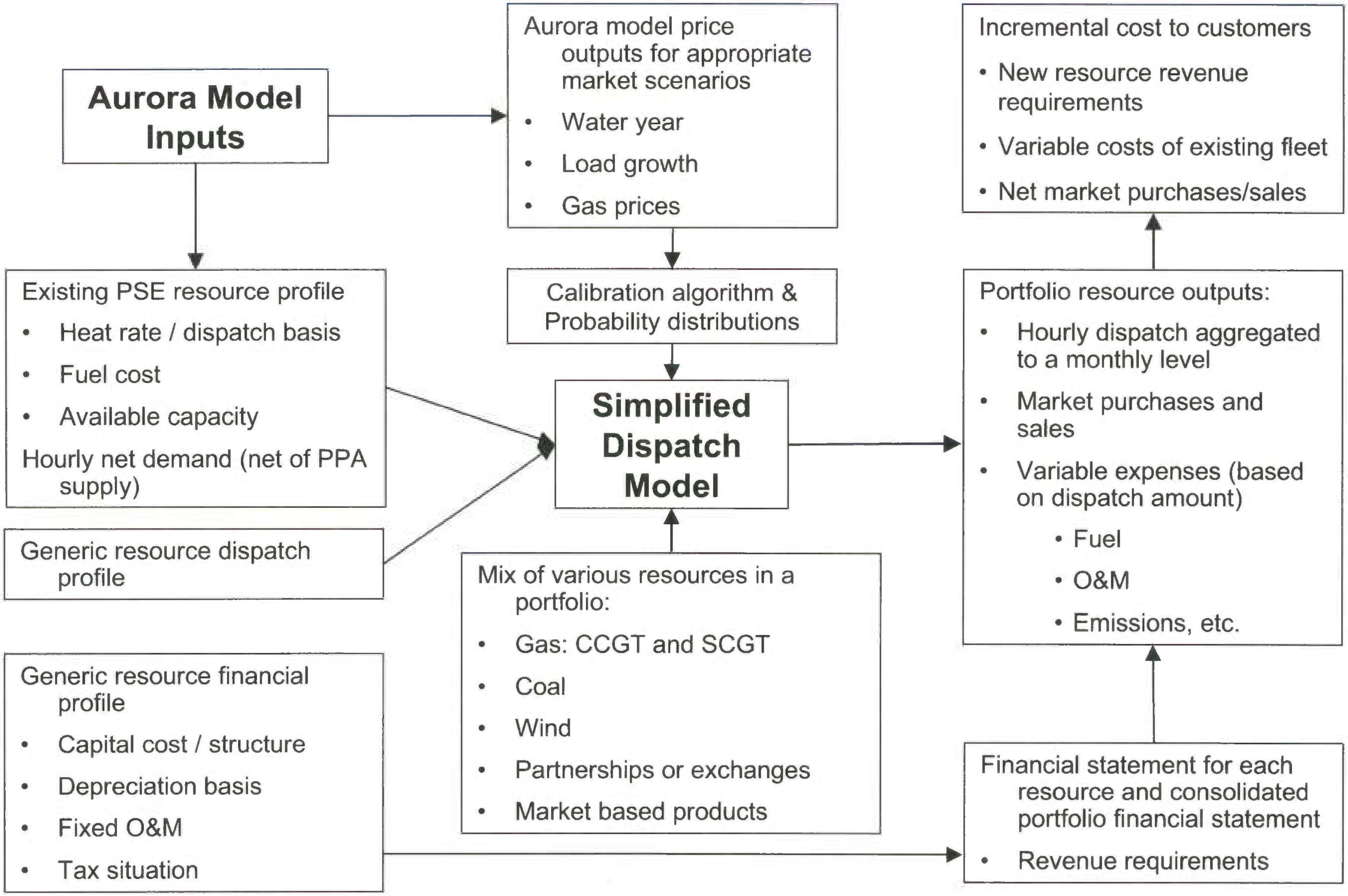
Modeling Process - Overview

The portfolio screening model is composed of two main parts:

- Dispatch Model Calculation
  - Utilizes actual power price output from Aurora for WA/OR region
  - Utilizes inputs from Aurora (plant profiles, Net Demand)
  - Uses Crystal Ball Monte Carlo simulation to achieve probability weighted results
  - Output from dispatch model includes MWh for an assumed portfolio of new generation resources and their variable (or incremental) costs (fuel, O&M, emissions, transmission, etc.)

- Financial Summary and Revenue Requirement Calculation
  - MWh produced and variable cost data from the dispatch model is used in conjunction with fixed cost assumptions to derive a 'bottom up' revenue requirement for each new resource being considered
  - A financial summary is generated for each technology that includes an income statement, cash flow summary and an approximation of regulatory asset base
  - Financial data from each new resource is then consolidated
  - The comparative incremental cost to customers for a particular resource portfolio is calculated by combining the variable cost of dispatch from the existing dispatchable PSE fleet, the variable emission cost from the existing PSE fleet, the cost of market purchases and net revenue from market sales with the revenue requirements from the new resource portfolio and taking the NPV of the 20-year analysis period at pre-tax WACC

Modeling Process Flow Chart



Dispatch Inputs and Methodology Summary

Net Demand Development

- Monthly demand and resource summaries extracted from Aurora for the forecast period (see 2003 example below) are used to develop Net Demand

Energy (aMW)	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Hydro	2003	1,106	906	993	1,022	1,114	1,116	1,026	852	536	652	732	800	905
Colstrip	2003	598	598	598	432	598	464	598	598	598	598	598	598	573
Encogen & CTs	2003	99	61	82	79	48	59	143	339	320	183	116	113	137
NUGs	2003	586	252	357	272	97	86	473	524	528	508	498	504	392
Contracts Purch/(Sale)	2003	504	478	299	247	149	136	72	44	33	210	363	390	242
Market Purchases	2003	96	419	291	251	135	193	14	18	197	232	301	498	219
Market Sales	2003	(135)	(8)	(71)	(79)	(70)	(52)	(348)	(291)	(141)	(52)	(53)	(22)	(111)
Total Demand	2003	2,853	2,705	2,548	2,224	2,071	2,001	1,977	2,084	2,071	2,330	2,555	2,879	2,357
Contracts	2003	504	478	299	247	149	136	72	44	33	210	363	390	242
Net Demand	2003	2,349	2,227	2,250	1,978	1,922	1,866	1,905	2,039	2,038	2,120	2,191	2,490	2,115

- The monthly Net Demand is derived by taking the total demand and subtracting contract purchases/(sales)
- The monthly Net Demand is converted to hourly Net Demand through the following process:
  - The 2003 hourly demand forecast is the basis for the load shape for all forecast years
  - An average demand is calculated for each month in 2003 and then a actual/average factor is calculated for each hour (demand in each hour in a month is divided by the monthly average)
  - These factors for each hour are then applied to the monthly Net Demand to create 8760 Net Demand profiles for each forecast period
  - The 2003 base year begins on Wed, the 2003 shape is applied to each forecast year beginning on the day the forecast year starts (e.g. Thursday in 2004, Saturday in 2005, etc.) (same as Aurora methodology)

Dispatch Methodology

- The hourly dispatch of the PSE fleet and the new resources considered in the planning portfolio is done on a month by month basis (this is due to size constraints within Excel)
- All resources (existing and contemplated) are divided into dispatchable and must run categories
- The dispatchable plants are:
  - PSE owned: Fredonia1&2, Fredonia 3&4, Frederickson 1&2, Whitehorn 2&3, Colstrip 1&2, Colstrip 3&4 and Encogen (dispatchable)
  - NUG's: March Point 1&2 (dispatchable), Sumas, and Tenaska
  - New resources: CCGT (including structured deals), SCGT, and coal
- The must run plants are:
  - PSE Owned: All hydro plants, and Encogen MR
  - NUG's: March Point 1&2 MR
  - New resources: Wind
- There are two primary data inputs to the dispatch logic from the dispatchable plants:
  - Dispatch Basis: This is the marginal cost of dispatch and is sum of variable O&M (assumed to be zero in most cases), fuel cost (calculated by running a "burner tip" $/MMBtu fuel cost through the plants heat rate to arrive at $/MWh), and any other incremental costs (e.g. transmission, etc.)
  - Dispatchable Capacity: The dispatchable capacity adjusts the net capacity for an asset by a forced outage rate applied evenly over all periods, and an planned outage rate applied when the outage is expected

Dispatch Methodology Continued

- The Must Run plants have only have Dispatchable Capacity as input to the dispatch logic
  - The must run portions of Encogen and March Point calculate the Dispatchable Capacity is the same fashion as the dispatchable portions of those plants
  - The wind units have their nominal capacity adjusted for monthly availability based on seasonal variations in wind patterns (the proxy is currently for wind located in the Basin & Range region of OR and ID)
  - The hydro unit Dispatchable Capacity is based on the monthly availability for the average water year in the 40-year hydro data set from NWPP and the hourly dispatch shape for a 2003 base year in Aurora
    - ✓ The hourly shape adjusts the monthly average is a similar fashion as the Net Demand
- The dispatch logic is as follows:
  - For each hour, the Dispatch Basis for each dispatchable plant is compared to the market price for that hour, if the Dispatch Basis is less than the market price, then the plant generates its Dispatchable Capacity for that hour, else, it does not dispatch that hour
  - The total generation from the dispatchable plants is summed for each hour
  - The total generation from the must run plants is added to the total generation from the dispatchable plants
  - The grand total of plant generation (dispatchable and must run) is compared to the Net Demand for each hour, if the amount generated is less than the Net Demand, then that amount represents a market purchase, if the amount generated is greater than Net Demand, than that amount represents a market sale
  - For every hour where there is a market sale or purchase, the market price at that hour is used to calculate the financial impact of the purchase or sale
- The major simplification from the dispatch logic in Aurora is that there is no provision for unit minimum run times, ramp rates, minimum dispatch levels, etc.

Thermal (Dispatchable and Must Run) Plant Profiles

Plant	Net Capacity (MW)	Heat Rate (Btu/KWh)	Forced Outage Rate (%)	VOM ($/MWh)	Fuel Cost (Note/$/MMBtu)	Planned Outage Period (Approx.)
Fredonia 1&2	202.1	11,569	16.87	2.12	Sumas + trans.	1 week in May
Fredonia 3&4	108.0	10,540	5.00	2.12	Sumas + trans.	1 week in May
Frederickson 1&2	141.0	12,450	14.26	2.12	Sumas + trans.	1 week in April
Whitehorn 2&3	134.4	11,987	13.23	2.12	Sumas + trans.	1 week in April
Colstrip 1&2	298.6	10,889	10.38	Inc. in fuel	0.45	2 weeks in May
Colstrip 3&4	359.9	10,695	8.29	Inc. in fuel	0.60	2 weeks in June
Encogen - Disp.	120.0	9,032	1.97	Inc. in fuel	Sumas + trans.	Inc. in FOR
March Point 1 - Disp.	0.0	8,500	0.20	Inc. in fuel	Sumas	Inc. in FOR
March Point 2 - Disp.	13.0	12,000	0.20	Inc. in fuel	Sumas	Inc. in FOR
Sumas	133.0	8,200	1.80	Inc. in fuel	Sumas	Inc. in FOR
Tenaska	245.0	8,700	0.30	Inc. in fuel	Sumas	Inc. in FOR
Encogen - MR	51.0	9,830	1.97	Inc. in fuel	Sumas + trans.	Inc. in FOR
March Point 1 - MR	85.0	8,500	0.20	Inc. in fuel	Sumas	Inc. in FOR
March Point 2 - MR	50.0	8,500	0.20	Inc. in fuel	Sumas	Inc. in FOR

Hydro and Renewable Plant Profiles

Hydro/Renewable Plants

Plant	Nominal Capacity (MW)	Monthly Availability Factor											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Upper Baker	104.9	28%	26%	21%	27%	47%	21%	57%	62%	13%	45%	65%	35%
Lower Baker	79.0	67%	52%	39%	55%	68%	43%	60%	79%	22%	66%	82%	74%
White River	62.5	69%	53%	46%	53%	65%	69%	45%	55%	6%	22%	64%	32%
Puget Small Plants	69.7	74%	76%	74%	82%	88%	87%	72%	53%	34%	41%	74%	77%
Wells	262.9	67%	54%	62%	65%	72%	73%	65%	53%	36%	36%	36%	45%
Rocky Beach	492.7	69%	56%	64%	67%	72%	78%	69%	55%	37%	38%	38%	47%
Rock Island 1	163.1	68%	69%	66%	65%	61%	61%	64%	66%	64%	64%	68%	65%
Wanapum	106.5	68%	55%	59%	46%	37%	45%	44%	32%	34%	35%	36%	46%
Priest Rapids	73.0	75%	63%	66%	41%	17%	33%	41%	32%	43%	44%	44%	55%
Rock Island 2	174.0	95%	65%	88%	92%	100%	100%	89%	57%	28%	31%	26%	52%
Wind (Basin & Range)	NA	119%	139%	107%	105%	94%	71%	56%	61%	72%	74%	159%	143%

Emissions Assumptions

Emission rate (T/GWh)	SO2	NOX	CO2	Source
Fredonia 1&2	-	0.00002	582.00	PSE
Frederickson 1&2	0.00080	0.03900	582.00	NPPC Generic
Fredonia 3&4	0.00080	0.03900	582.00	PSE
Whitehorn 2&3	0.000003	0.00002	582.00	PSE
Colstrip 1&2	2.27613	2.09048	1,119.24	EPA
Colstrip 3&4	0.50220	2.19521	1,097.69	EPA
Encogen (Dispatchable)	0.00200	0.03900	411.00	NPPC Generic
March Point 1&2 (Dispatchable)	0.00200	0.03900	411.00	NPPC Generic
Sumas	0.00200	0.03900	411.00	NPPC Generic
Tenaska	0.00200	0.03900	411.00	NPPC Generic
CCGT	0.00200	0.03900	411.00	NPPC Generic
SCGT	0.00080	0.05523	582.00	NPPC Generic
Coal	0.38200	0.35000	1,012.00	NPPC Generic
Escalation	-	-	-	
Base Cost/Ton	200.00	1,750.00	-	

Financial Summary and Revenue Requirement Calculation

Financial Summary and Revenue Requirement Calculation - *Assumptions and Methodologies*

Assumptions utilized in the financial summary portion of the portfolio screening model generally fall into the following categories:

- Dates used for analysis period
  - Planning horizon for resource acquisition is 10 years beginning Jan. 1, 2003
  - Model assumes 'financial close' date of 12/31/2002 as basis for the model starting point
  - Analysis period is 20 years (model ends 12/31/2023)

- Expense / Capital escalation rates
  - Both fixed and variable O&M currently assume a 2 ½% annual escalation factor
  - Both periodic and acquisition capex assume a 2 ½% annual escalation factor
    - ✓ Methodology – The model assumes two kinds of additional capex: 'incremental capex' and 'acquisition capex.' 'Incremental capex' are capital expenditures (plant) acquired on an annual basis using a $/Kwh valuation. The current model assumes that 'incremental capex' is funded through available cash rather than by debt. Alternatively, the model assumes that 'acquisition capex', or capital expenditures related to acquiring new generation MW during the 10 year planning horizon, are financed using the debt to equity ratio supplied by PSE (60% debt to 40% equity).

- Capital Costs (Table below outlining Incremental and New Acquisition Capex in $/kw)

		CCGT	SCGT	Coal	Wind	Solar	Geothermal
All in Cost - New Acquisition ($/kw)		$621	$730	$1,400	$1,030	$6,000	$900
Incremental Capex ($/kw Capacity)	*(Placeholder)*	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00

Financial Summary and Revenue Requirement Calculation - *Assumptions and Methodologies - continued*

Assumptions utilized in the financial summary portion of the portfolio screening model generally fall into the following categories – continued:

- O&M Costs (Table below outlining Fixed rates in $/kw-yr and Variable O&M rates in $/MWh)

	CCGT	SCGT	Coal	Wind	Solar	Geothermal
Fixed O&M ($/kw-yr)	$24.10	$23.74	$25.00	$20.00	$24.00	$24.00
Variable O&M ($/MWh)	$2.80	$8.00	$1.75	$1.00	$0.80	$3.00

- Finance and Regulatory assumptions
  - Cost of equity and debt (used for both the WACC and debt amortization calculations) – 11.0% and 7.4% respectively
  - Pre / After Tax WACC – 8.76% and 7.30% respectively
  - Conversion Factor (gross-up factor used in revenue requirement calculation) – 62.02%
    - ✓ Roughly equivalent to (1- Federal tax rate and miscellaneous regulatory fees)
- Heat Rate and Forced Outage Rates

	CCGT	SCGT	Coal	Wind	Solar	Geothermal
Heat Rates	7030	9960	9550			
Forced Outage Rates	5.00%	3.60%	7.00%	72.00%	40.00%	5.00%

Financial Summary and Revenue Requirement Calculation - *Calculation Detail*

The revenue requirement for a specified portfolio utilizes a 'bottom-up' approach where total fixed and variable costs are used to back solve for the appropriate revenue stream that would yield an operating income stream sufficient to provide a desired regulated rate of return. The following discussion outlines how individual components of fixed and variable expenses are calculated:

- Variable Costs – Fuel and Variable O&M
  - Fuel expense is calculated by multiplying the assumed number of MWh dispatched or generated each month, times the heat rate of the plant times the appropriate fuel curve (i.e. gas or coal)
  - Variable O&M is calculated by taking the appropriate VOM factor (as provided by PSE and illustrated on the previous slide), applying the VOM escalation percentage adjusted for time, and multiplying the resulting inflation adjusted VOM factor (in $/Kwh) times the number of Kwh produced for the selected technology
- Fixed Costs – Fixed O&M
  - The FOM Factor provided by PSE should includes all categories of fixed costs associated with the various technologies under consideration
  - The fixed cost calculation is similar to that of Variable O&M in that the FOM factor (quoted in $/Kw) provided by PSE is inflation adjusted using the escalation factor illustrated on the previous slide and multiplied times the plant capacity (rather than the number of Kwh produced)
- Depreciation - Book and Tax
  - Book – Modeled value assumes 30 year recovery on all capital additions
  - Tax – The portfolio model contains flexibility to select from 5, 10, 15 and 20 year MACRS (half-year convention)
    - The current test cases utilize 5 year MACRS for 'green' resources, 15 year MACRS for simple and combined cycle gas and 20 year MACRS for coal fired resources.

Financial Summary and Revenue Requirement Calculation - *Calculation Detail - continued*

- **Debt Service – Principal and Interest**
  - The model assumes that generation purchased during the 10 year planning horizon is financed 40% with equity and 60% with debt
  - Each time new generation is acquired, the model assumes new debt is issued and the levelized, mortgage style payment is reset to yield a 20 year amortization (loan tenor may be any term – 20 years is a placeholder)
    - ✓ To simplify the debt service calculation, we assume that only new generation is financed. Incremental capital projects are paid for with available cash. Debt service is modeled with a tranche of debt for each category of generation. Any time incremental generation is purchased, the payment related to that tranche is reset to reflect the additional principal and repayment term is renewed (reset to 20 year term in our current case).
  - The interest rate is assumed to be 7.4%

- **Tax – Current and Deferred**
  - Current taxes are computed on taxable income calculated using tax depreciation rates previously discussed
  - Differences between book and tax depreciation are the only items considered to generate book/tax differences that give rise to deferred taxes.
  - Currently, the model assumes a 35% US Federal marginal rate with no state income tax rate

Financial Summary and Revenue Requirement Calculation - *Cost to Customer*

- **Cost to customer is the point at which various alternative portfolios will be measured**
- **Cost to Customer in the portfolio model is calculated as follows:**
  - ✓ **The sum of the annual revenue requirement, emissions, variable costs and costs of market power purchases are computed on an annual basis. These annual totals for the 20 year analysis period are discounted using the pre-tax WACC to arrive at a present value.**

INCREMENTAL COST TO CUSTOMER	
Revenue Requirement - Resource Portfolio	xxx
Emissions - Fleet	xxx
Variable Costs - Existing Fleet	xxx
Revenue from Power Sales	xxx
Cost of Power Purchase	xxx
Cost to Customer	*XXX*
NPV Cost To Customer (Pre-Tax WACC)	**xxx**