EXHIBIT NO. ______ (CJB-20)
DOCKET NO. ____________
2003 POWER COST ONLY RATE CASE
WITNESS: CHARLES J. BLACK

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

DIRECT TESTIMONY OF
CHARLES J. BLACK
ON BEHALF OF PUGET SOUND ENERGY, INC.

Exhibit CJB-20 Portfolio Screening Model Inputs

Input	Description / Discussion	Input Value (04/30/2003 vs. 08/31/2003 if applicable)
Capital Cost	All-in capital cost of construction	CCGT - 04/30/2003: $645/kW CCGT - 08/31/2003: $710/kW SCGT - $441/kW Coal - $1,500/kW Wind - $1,030/kW Duct Firing - $150/kW
Heat Rate	The average heat rate changed from the April LCP to the August LCP update because PSE went from static heat rates over time to incorporating efficiency gains. The static numbers in the April LCP were from a Tenaska study, and the August update values were from the EIA 2003 Energy Outlook	CCGT - 04/30/03: 6,900 BTU/kWh CCGT - 08/31/03: 6,856 BTU/kWh SCGT - 04/30/03: 11,700 BTU/kWh SCGT - 08/31/03: 10,817 BTU/kWh Coal - 04/30/03: 9,425 BTU/kWh Coal - 08/31/03: 8,922 BTU/kWh Duct Firing - 04/30/03: 9,100 BTU/kWh Duct Firing - 08/31/03: 9,100 BTU/kWh Wind – N/A (Please see Exhibit VII-3 from the 08/31/03 LCP Update for the efficiency gains through 2015)
Forced Outage Rate	Annual forced outage rate – decrements the available capacity equally year round. The wind assumption is based on the "Cascades and Inland" profile developed by the NPPC	CCGT - 5% SCGT - 3.6% Coal - 7% Wind - 70% Duct Firing - 0%
Fixed O&M	Fixed O&M excluding gas and electric transportation	CCGT - $11/kW-year SCGT - $3/kW-year Coal - $20/kW-year Wind - $26.1/kW-year Duct Firing - $0/kW-year

Fixed Gas Transportation	Fixed cost for pipeline gas	CCGT - $15.55 / kW-year SCGT - $15.74 / kW-year Duct Firing - $15.55 / kW-year Coal/Wind – N/A
Fixed Electric Transmission	Fixed cost for electric transmission is assumed to be 1 BPA wheel	CCGT - $14.88 / kW-year
	Assumed SCGT would reside in PSE territory	SCGT - $0 / kW-year
	Fixed cost for electric transmission is assumed to be 2 BPA wheels	Coal - $29.76/ kW-year
	Fixed cost for electric transmission is assumed to be 1 BPA wheel based on nameplate capacity	Wind - $14.88 / kW-year
	Fixed cost for electric transmission is assumed to be 1 BPA wheel	Duct Firing - $14.88 / kW-year
Transmission Losses	Transmission Losses	1.6%
Variable O&M	Variable O&M expenses excluding variable fuel expenses	CCGT - $2 / MWh SCGT - $2 / MWh Coal - $2 / MWh Wind - $1 / MWh Duct Firing - $2 / MWh
Fuel Basis Differential (variable fuel expense)	The fuel basis differential is an adder to the natural gas commodity cost that is intended to cover variable costs. In the 04/30/03 LCP, the fuel basis differential was $0.50 / MMBtu. This assumption was modified in the 08/31/03 LCP Update as the breakdown between fixed and variable natural gas costs were refined. For a detailed discussion of the change please see Chapter VII, Section A of the 08/31/03 LCP update	CCGT - 04/30/03: $0.50 / MMBtu CCGT - 08/31/03: $0.11 / MMBtu SCGT - 04/30/03: $0.50 / MMBtu SCGT - 08/31/03: $0.18 / MMBtu Duct Firing - 04/30/03: $0.50 / MMBtu Duct Firing - 08/31/03: $0.11 / MMBtu

Book Depreciation	Depreciation for book purposes	CCGT - 30 years SCGT - 30 years Coal - 30 years Wind - 20 years Duct Firing - 30 years
Tax Depreciation	MACRS Depreciation	CCGT - 15 years SCGT - 15 years Coal - 20 years Wind - 5 years Duct Firing - 15 years
Renewable Tax Credit	Tax credit applied to renewable (wind in the case of the LCP). Otherwise known as the production tax credit (PTC), we assumed that the PTC stayed in effect for the duration of the 20-year planning horizon	$18 / MWh
Emission Rates - CCGT	Emission rates for SO2, NOX, and CO2	SO2: 0.002 Tons / GWh NOX: 0.039 Tons / GWh CO2: 411 Tons / GWh
Emission Rates - SCGT	Emission rates for SO2, NOX, and CO2	SO2: 0.0008 Tons / GWh NOX: 0.0552 Tons / GWh CO2: 582 Tons / GWh
Emission Rates - Coal	Emission rates for SO2, NOX, and CO2	SO2: 0.38 Tons / GWh NOX: 0.35 Tons / GWh CO2: 1,012 Tons / GWh
Emission Rates – Duct Firing	Emission rates for SO2, NOX, and CO2	SO2: 0.0008 Tons / GWh NOX: 0.213 Tons / GWh CO2: 582 Tons / GWh
Emission Costs	Credit costs for emissions	SO2: $200 / Ton NOX: $0 / Ton CO2: $0 / Ton
Analysis period	The period over which the evaluation occured	20 years
Resource planning	The period over which assets are installed	04/30/03: 10 years

horizon	to meet planning standard need based on the applicable planning standard	08/31/03: 20 years
Inflation escalation factor for O&M	Rate at which variable and fixed O&M escalate	2.5%
Inflation escalation factor for Capital Cost	Rate at which capital construction cost of the various technologies escalate	2.5%
Insurance Cost	Expense to insure the new asset in the PSE portfolio	0.13 % of year end adjusted rate base
Property Taxes	Property Taxes	1.1% of year end adjusted rate base
Conversion Rate	The revenue sensitive items were stripped out of the conversion rate for the 08/31/03 LCP Update to simplify the revenue requirement calculation	04/30/03: 62.02% 08/31/03: 65%
Federal tax rate	Federal tax rate	35%
Pretax cost of debt	Pretax debt rate for PSE	7.4%
Cost of Equity	Tax adjusted cost of equity	11%
Capital structure	Long-term debt, preferred stock, and equity percentage for PSE.	Debt: 52.43% Preferred Stock: 2.57% Equity: 45%
Pretax WACC	Weighted average cost of capital with no tax effect for the debt	8.95%
WACC	After tax weighted average cost of capital	7.61%
Uncertainty factor distributions	The uncertainty distribution used by the Crystal Ball software for purposes of Monte Carlo analysis. There are three uncertainty variables in the analysis; power prices, gas prices, and hydro availability. The standard deviations are measured as a percent of the mean	Power: - Lognormal, 73% standard deviation Gas – Lognormal, 59% standard deviation Western Hydro System – Normal, 12.1% standard deviation Mid-Columbia Hydro System – Normal, 8.3% standard deviation
Uncertainty factor correlations	The three uncertainty factors have associated correlation factors associated with them. The values represented here are reciprocal.	Gas to Power: 67% Gas to Hydro: -24% Power to Hydro: -32%
Imputed debt rate	Bond rating agencies treat fixed payments associated with long-term power purchase agreements analogously with long-term debt with the subsequent impact on	40%

	coverage ratios and ultimately credit rating. PSE utilizes the "S&P methodology" for assessing the balance sheet impact of debt imputation as a result of entering into long term power purchase agreements. The imputed debt rate is the fraction (%) of the NPV of the capacity charge stream associated with any long term PPA that gets imputed as debt to the balance sheet by S&P	
Imputed Debt Discount Rate	The NPV of the of the capacity charge stream associated with any long term PPA is calculated using a specified discount rate using a mid-year convention	10%
Cost of Equity for the Equity Offset	To maintain the original capital structure before debt is imputed on the balance sheet, equity must be increased this is known as the "equity offset". The cost of this equity is the PSE pretax equity cost.	16.92%
Load Forecast and Load Shape	The screening model performs an hourly dispatch against hourly prices generated in AURORA. The total generation of existing and potential new resources is then compared to the load to assess "market activity". The PSE load forecast is represented in monthly aMW terms. These monthly	Load Forecast: 04/30/03: Please see section ______ from the 04/30/03 LCP for a detailed description of the load forecast used 08/31/03: Please see Chapter 3, Section A of the 08/31/03 LCP Update for a detailed description of the load forecast used Load Shape: The hourly load shape is based on historical PSE loads and SEA-TAC weather. This shape was used in the 2001 general rate case and in the current PORC.
Hydro Availability and Dispatch Profile	The availability and dispatch profile is the same as is used in AURORA	40-year average regulation run – 7/28/03
Regional Power Prices	The basis on which the dispatch occurs and market activity is valued	04/30/03: AURORA updated March 2003 08/31/03: AURORA updated June 2003