EXHIBIT NO. ___(WJE-5HC)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: W. JAMES ELSEA

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-06____** **Docket No. UG-06____**

FOURTH EXHIBIT (HIGHLY CONFIDENTIAL) TO THE
PREFILED DIRECT TESTIMONY OF
W. JAMES ELSEA
ON BEHALF OF PUGET SOUND ENERGY, INC.

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FEBRUARY 15, 2006

Exhibit 5a

Assumptions for Financial Pro Forma

Public Utility District No. 1 of Chelan County

Power Sales Agreement
and
Transmission Agreement

Table of Contents

I. Assumptions and Definitions

Contract:	Power Sales Agreement ("PSA" or the "Agreement")
Seller:	Public Utility District No. 1 of Chelan County (the "District")
Buyer:	Puget Sound Energy ("PSE")
Power Source:	Chelan Power System comprising the Rocky Reach and Rock Island projects, both hydroelectric dams located on the Columbia River in central Washington with installed capacities of 1,287 MW and 660 MW, respectively.
Output:	25% share of Chelan Power System Approximately: 243 aMW energy (60 year average) 487 MW capacity
Term:	November 1, 2011 through October 31, 2031
Project Availability Dates:	November 1, 2011 for Rocky Reach July 1, 2012 for Rock Island
Signing Date:	Projected to occur Q1 2006

Conditions precedent to effectiveness:

(1) No default shall have occurred and be continuing, as of each respective Project Availability Date, under the current contract(s) between the Parties.

(2) No Event of Default or Potential Event of Default exists under the Power Sales Agreement.

(3) The representations contained in Article IV of the PSA continue to be true.

(4) The Existing Rocky Reach Power Sales Contract shall have terminated on or prior to the Rocky Reach Project Availability Date.

(5) The Existing Rock Island Power Sales Contract shall have terminated on or prior to the Rock Island Project Availability Date.

(6) No termination described in Section 3.03 of the PSA has occurred.

II. The Projection

This document and its attachments (the "Projection") illustrate the projection of financial results to PSE from its Upfront and Prepayments, and from its ongoing purchase of energy and capacity from the District. Although the Agreement will be integrated into both PSE's power portfolio and financial books, the pro forma financial statements are presented for clarity as though the Agreement were a contract of a stand-alone subsidiary.

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III. Capital and O&M Cost Assumptions

- **Rehabilitation and Modernization Capital.** PSE estimates future rehabilitation and modernization costs of $[redacted] million and $[redacted] million (nominal capital costs) for Rocky Reach and Rock Island, respectively, during the term of the Agreement. Such estimates were prepared by using past results and budgets, estimated equipment service lives, feasibility and condition assessment reports prepared by the District or engineering consultants to the District, and information gathered during meetings with District personnel. Annual details are contained in Exhibit 5b, pages 4 – 11, and PSE's forecast methodology is described in Exhibit 5c.

- **FERC Licensing.** Significant investment is required in support of FERC licensing and compliance. The Rocky Reach project license expires in 2006 and the District reached a multi-party settlement agreement in December 2005, which is estimated to cost approximately $[redacted] million (nominal O&M and capital costs) during the term of the Agreement. Annual details are contained in Exhibit 5b, pages 4 – 11, and PSE's forecast methodology is described in Exhibit 5c.

  The Rock Island project license expires in 2028. PSE has used the Rocky Reach process and expected settlement agreement as a proxy for future cost requirements, which are estimated at $[redacted] million (nominal O&M and capital) during the contract term. Additional licensing costs for both Rocky Reach and Rock Island are forecast

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in the years beyond the contract term, which ends in 2031, and are not included in the analysis. The District has agreed not to accelerate payment of costs associated with measures required or agreed upon for the relicensing of either Project in advance of the date(s) necessary to comply with existing and anticipated FERC and other regulatory requirements or settlement agreements related to relicensing.

- **Operation and Maintenance.** PSE has evaluated historical O&M budgets for both Rocky Reach and Rock Island and, using a 2.0% real growth rate and a 2.5% escalation factor, estimates future normal / recurring O&M costs of $[redacted]billion and $[redacted]billion for Rocky Reach and Rock Island, respectively, during the term of the Agreement. These totals include the licensing O&M discussed above. An annual forecast of O&M is shown in Exhibit 5b pages 6 and 7.

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IV. Debt Service Assumptions

Per the Agreement, debt service is categorized as either Outstanding Debt Obligations or Future Debt Obligations.

- **Outstanding Debt Obligations**. Existing debt service obligations for Rocky Reach and Rock Island total $[redacted]million and $[redacted]million for Rocky Reach and Rock Island, respectively, during the new contract term. See Exhibit 5b page 4.

  Financing costs for Outstanding Debt Obligations, as of the signing date, are shown below (and also in the Power Sales Agreement) as Schedule A-1. Schedule A-1 is developed from a compilation of outstanding bonds for Rocky Reach (from 1968 Series through 2005 Capital Appreciation Bonds) and for Rock Island (Series 1955 through 2003 re-loans of the 1995A Series). The District used an assumption of 7.8% (interest and issuance costs) for the pricing of bonds that are periodically re-priced, such as the 1997A Series.

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POWER SALES AGREEMENT

SCHEDULE A-1
SCHEDULE OF FINANCING COSTS WITH RESPECT TO DEBT OBLIGATIONS OUTSTANDING AS OF THE SIGNING DATE

	Principal	Interest	Total Principal & Interest	Reserve & Contingency	Total Debt Service	Total Debt Obligation Outstanding
Nov-Dec 2011	2,852,437	2,379,448	5,231,886	333,333	5,565,219	233,562,832
2012	23,987,606	23,530,694	47,518,300	3,134,250	50,652,550	542,715,735
2013	31,996,487	32,095,381	64,091,868	4,268,500	68,360,368	510,563,330
2014	34,118,081	30,360,600	64,478,682	4,268,500	68,747,182	476,276,282
2015	33,502,319	28,687,729	62,190,049	3,268,500	65,458,549	440,540,853
2016	33,324,797	26,991,602	60,316,399	2,268,500	62,584,899	407,017,620
2017	33,684,144	25,173,513	58,857,657	2,268,500	61,126,157	373,118,431
2018	25,841,036	22,976,565	48,817,600	2,268,500	51,086,100	347,044,352
2019	23,874,302	21,050,139	44,924,441	2,268,500	47,192,941	322,917,501
2020	25,338,963	19,640,037	44,978,999	2,268,500	47,247,499	297,304,851
2021	26,157,575	18,122,238	44,279,814	2,268,500	46,548,314	271,001,958
2022	27,586,910	16,511,202	44,098,112	2,268,500	46,366,612	243,415,048
2023	29,200,050	14,820,353	44,020,403	2,268,500	46,288,903	214,214,998
2024	30,438,134	13,050,228	43,488,362	2,268,500	45,756,862	183,776,864
2025	29,728,862	11,183,738	40,912,600	2,268,500	43,181,100	154,048,001
2026	29,820,252	9,355,448	39,175,700	2,268,500	41,444,200	124,227,749
2027	30,162,959	7,535,267	37,698,226	2,268,500	39,966,726	94,064,790
2028	30,851,917	5,708,472	36,560,390	2,448,740	39,009,129	63,212,872
2029	17,519,006	3,175,850	20,694,856	1,073,951	21,768,807	26,873,687
2030	6,833,512	1,607,282	8,440,794	-	8,440,794	20,040,175
2031	5,083,965	1,205,474	6,289,439	-	6,289,439	14,956,210

➤ **Future Debt Obligations**. Debt obligations that are incurred after the Signing Date are called Future Debt Obligations. For its share of these obligations, PSE will (a) pay, commencing November 1, 2011, the monthly amortization of the Assumed Debt Service on such Debt Obligations attributable to Rocky Reach, and (b) pay, commencing July 1, 2012, the monthly amortization of the Assumed Debt Service on such Debt Obligations attributable to Rock Island. Following the issuance or incurrence of any Future Debt Obligation, the District will make available a written schedule showing the Capital Improvements expected to be financed by the District from the proceeds thereof, the estimated Average Service Life of such Capital Improvements as determined by the District and the scheduled monthly Financing Costs associated with such Debt Obligations.

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PSE assumed [redacted] annual interest and a term of 25 years for Future Debt Obligations. The annual interest rate is based upon an estimate of the District's taxable borrowing cost of [redacted] multiplied by the 110% adjustment factor as defined in the Power Sales Agreement, Appendix A, page 2.

As shown in Exhibit 5b, page 4, PSE estimates the amount of incremental debt service for Future Debt Obligations to be $[redacted] million for Rocky Reach and $[redacted] million for Rock Island (100% of Chelan Power System) during the term of the Agreement.

The total amount of incremental debt service depends on the forecast of Future Debt Obligations, which in turn depends upon the level of "pay-as-you-go" capital payments in the form of the Debt Reduction Charge and the Capital Recovery Charge. For the Projection, PSE assumed the highest level of "pay-as-you-go" cash payments allowed by the District per the Agreement – 3% for the annual Debt Reduction Charge and 50% for the Annual Capital Recovery Charge.

The Debt Reduction Charge is computed by multiplying the Debt Reduction Charge Percentage (which ranges from 0% to 3% as determined by the District) for the

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Contract Year times PSE's 25% share of Debt Reduction Charge Obligations for such Contract Year. The Debt Reduction Charge Obligations are the aggregate principal amount of all Debt Obligations assumed to be outstanding as of the first day of each Contract Year.

The Capital Recovery Charge is computed by multiplying the Capital Recovery Charge Percentage (which ranges from 0% to 50% as determined by the District) for the Contract Year times the Capital Recovery Charge Base for such Contract Year. The Capital Recovery Charge Base is equal to $25,000,000, the District's estimate of its average annual capital requirement during the term of the Agreement, expressed in 2004 dollars and adjusted annually for inflation.

V. Other Modeling Assumptions

- **Cost of Capital.** The Projection uses PSE's allowed return as specified in the 2005 General Rate Case Order #6, DOCKET NOS. UG-040640 and UE-040641 (consolidated).

	Ratio	**Cost**	**Weighted Cost**
Long-term Debt	47.53%	6.88%	3.27%
Short-term Debt	3.11%	4.81%	0.15%
Trust Preferred	6.32%	8.60%	0.54%
Preferred Stock	0.04%	8.51%	0.0034%
Common Equity	43.00%	10.30%	4.43%
Total	**100.00%**		**8.40%**

- **Cost Escalation.** Costs were escalated using a 4.5% annual rate, assuming 2.5% inflation and 2.0% real cost escalation.

- **Capacity and Energy.** A 25% share of the Chelan Power System is expected to produce about 243 aMW or 2,125,000 MWh per year.

Capacity (MW)	**100%**	**25%**
Rocky Reach	1,287.0	321.8
Rock Island	660.0	165.0
System Total (MW)	1,947.0	486.8

Average Energy (aMW)	**100%**	**25%**
Rocky Reach	641.6	160.4
Rock Island	328.6	82.2
System Total (aMW)	970.2	242.6

- **Hydro uncertainty.** PSE evaluated the hydro variability using Final Regulation, FR06, a forecast developed by the Northwest Power Pool for 70 water years from 1929 through 1998. The variability of a single water year has a 12.7% coefficient of variation (standard deviation / mean) and the variability for a set of 20 water years has a 4.7% coefficient of variation. The results are presented in Exhibit 2, section 3.

VI. Income Statement Pro Forma

The following income statement summary depicts totals during the term of the Agreement as well as for selected years throughout the term. On a nominal basis, the total revenue requirement during the term of the Agreement is about $[redacted] or approximately $[redacted] on a levelized unit cost basis. A complete pro forma income statement is contained in Exhibit 5b, pages 1 and 2.

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PSE Board of Directors
January 10, 2006

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Exhibit 5a, Confidential and Proprietary
PSA - Stand Alone Financial Pro Forma

Line #	Income Statement $000	2011-2031	2012	2015	2020	2025	2030
1	Operating Revenue Requirement						
2							
19	Total Purchased Power Expense						
20							
21	Amortization of Regulatory Asset						
22							
25	Total Income Tax						
26							
27	Total Operating Expenses						
28							
29	Operating Income	REDACTED					
30							
32	AFUDC						
34							
35	Income Before Interest Charges						
36					REDACTED		
37	Interest Expense						
38							
40	Less: Preferred Stock Dividends						
41	Income for Common Stock						
42							
43	Beginning Ratebase (Regulatory Asset)						
49	ROR (Op. Inc. on Beginning Ratebase)						
50							
51	Unit Cost Calculation						
52	Operating Revenue Requirement						
53	Energy GWH						
54	PPA Cost per MWh						
55							
56	Imputed Debt (S&P 30% Risk Factor)						
57	Cost of Equity Offset						
58	Unit Cost of Equity Offset $/MWh						
59							
60	Total Cost Including Equity Offset $/MWh						

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The following is a line by line description of the pro forma income statement provided in Exhibit 5b, pages 1 and 2.

Revenues

Operating Revenue Requirement, Line #1

The Projection calculates revenues required to recover PSA costs including a return on pre-payments (regulatory assets) included in the rate base, as well as fixed and variable operating expenses. The rate-recovery mechanism modeled assumes that all costs are recovered in a timely manner.

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O&M and Debt Service

Rock Island I & II O&M, Line #5 PSE has projected recent O&M budgets for Rock Island, using a 2.0% real growth rate and a 2.5% escalation factor, and estimates future normal / recurring O&M costs of $[redacted]billion for Rock Island during the term of the Agreement. PSE's share would be 25% of this forecast amount.

Licensing studies as O&M, Line #6 The Rock Island project license expires in 2028. PSE has used the Rocky Reach process and expected settlement agreement as a proxy for future cost requirements. The Agreement provides that re-licensing costs associated with studies and the administrative process will be expensed as O&M. Such costs, anticipated in 2024 through 2029, are expected to total $[redacted]million in nominal dollars. PSE's share would be 25% of this forecast amount.

Credit for Prepayment Requirement, Line #7 The District shall apply any unused portion of the Prepayment amount, without interest, to the last payment(s) due from the Purchaser under this Agreement. The Projection credits the $18.5 million Prepayment against PSE's contract payments in 2031.

Rocky Reach O&M, Line #8 PSE has projected future O&M budgets for Rocky Reach using a 2.0% real growth rate and a 2.5% escalation factor, and estimates future normal / recurring O&M costs of $[redacted]billion during the term of the Agreement. PSE's share would be 25% of this forecast amount.

Rock Island I & II and Rocky Reach Debt Service, Line #9 & #10 Debt service is categorized for either Outstanding Debt Obligations or Future Debt Obligations. Lines #9 and #10 include both existing debt service for Outstanding Debt Obligations and incremental debt service for Future Debt Obligations.

Other Contract Charges

Transmission Charge, Line #12 The District requires payment for the use of and wheeling across the Chelan Transmission System by PSE to transmit PSE's share of Output to PSE or a third party transmission provider. PSE and the District are currently finalizing a separate Transmission Agreement, under which the District has indicated it will charge PSE a FERC methodology-based tariff for PSE's use of the Chelan Transmission System. All Transmission Charge payments are non-refundable.

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Working Capital Charge, Line #13

The District requires a non-refundable payment of $2.5 million per project (stated in 2004 dollars) to be paid on the Project Availability Date to provide the projects an adequate working capital balance. This amounts to estimated initial payments of $3.4 million in November 2011 for Rocky Reach, and $3.5 million in July 2012 for Rock Island. In addition, the District may, from time to time during any Contract Year, require payment of an amount equal to the product of the Purchaser's percentage multiplied by any additional working capital necessary, as reasonably determined by the District.

Coverage Fund Charge, Line #14

The District requires a non-refundable Coverage Fund Charge payment equal to the positive difference, if any, between the product of the Purchaser's percentage multiplied by 15% multiplied by the District's outstanding debt obligations during each contract year, minus Coverage Fund Payments previously paid by the Purchaser. Payments would first be due within 30 days of each Project Availability Date. PSE expects this amount to total approximately $[redacted] million (nominal) during the term of the Agreement.

Debt Administrative Charge, Line #15

The District requires a Debt Administrative Charge as remuneration for the use and value of the District's current AA debt credit rating and for the District's management of debt associated with the Chelan Power System. The Debt Administrative Charge is calculated annually as the product of 1.0% multiplied by the Purchaser's percentage multiplied by the principal balance of Chelan Power System debt obligations outstanding at the beginning of each Contract Year. All Debt Administrative Charge payments are non-refundable.

Interest (Credit) on DRC and CRC, Line #16

The District agrees to invest any unexpended amounts of the Debt Reduction Charges and the Capital Recovery Charges during any Contract Year. The interest benefit is shown as a credit to costs for ease of modeling. In reality, the interest earned would reduce additional Debt Reduction and Capital Recovery Charges.

Debt Reduction Charge (DRC), Line #17

The District intends to reshape costs associated with the Chelan Power System through a "pay-as-you-go" capital expenditure funding program. The Debt Reduction Charge is a requirement of the District and the first of two charges intended to facilitate this program. Receipts may be used to purchase, redeem or defease debt of the Chelan Power System, to fund deposits to Reserve and Contingency Funds or to fund capital improvements related to the Chelan Power System. The Debt Reduction Charge is calculated per contract year as the product of the Purchaser's percentage multiplied by the debt reduction charge percentage (ranging from 0% to 3% per year as determined by the District), multiplied by the principal amount of debt obligations outstanding and attributable to the Chelan Power System. All Debt Reduction Charge payments are non-refundable.

The Projection assumes a 3% rate for the duration of the Agreement, thus providing a conservative (high) cost estimate.

Capital Recovery Charge (CRC), Line #18

The Capital Recovery Charge is the second of two charges required by the District to facilitate the "pay-as-you-go" capital expenditure funding program and reshaping of Chelan Power System costs. Similar to the Debt Reduction Charge, Capital Recovery Charge receipts may be used to purchase, redeem or defease debt of the Chelan Power System, to fund deposits to Reserve and Contingency Funds or to fund capital improvements related to the Chelan Power System. The Capital Recovery Charge is calculated per contract year as the product of the Purchaser's percentage multiplied by the capital recovery charge percentage (ranging from 0% to 50% per year as determined by the District), multiplied by the District's estimated average annual capital requirements (the "Capital Recovery Charge Base," currently estimated at $25,000,000 in 2004 dollars) adjusted for inflation and as otherwise adjusted from time to time by the District. All Capital Recovery Charge payments are non-refundable.

The Projection assumes a 50% rate for the duration of the Agreement, thus providing a conservative (high) cost estimate.

Total Purchased Power Expense, Line #19

Total Purchased Power Expense is the subtotal of O&M, licensing, debt service, transmission, working capital, coverage fund, debt administration as well as the Debt Reduction and Capital Recovery Charge. Line #19 is the sum of lines #5 through #18.

<u>Other Income Statement Lines</u>

Amortization of Regulatory Asset, Line #21

The amortization of regulatory asset assumes that the WUTC allows PSE to capitalize the upfront payment of $89 million and the prepayment requirement of $18.5 million (see also line #44). The regulatory asset is amortized over the term of the contract.

For modeling simplicity, amortization is spread evenly over 20 calendar years from 2012 through 2031. Actual accounting would amortize beginning November 1, 2011 through October 31, 2031.

Current Income Tax, Line #23 Current Income Tax is the calculation of taxable income multiplied by a 35% effective Federal Income Tax rate. Taxable income arises from the allowed return earned on the regulatory asset, otherwise this agreement is a pass-through of the costs and hydro generation benefits to PSE customers.

Deferred Tax, Line #24 There is no deferred tax in this model since the amortization of the regulatory asset for book purposes is equal to the amortization for tax purposes.

Total Income Tax, Line #25 Sum of current and deferred income tax.

Total Operating Expenses, Line #27 Sum of purchased power expense (line #19), plus amortization of regulatory asset (line #21), plus total income tax (line #25).

Operating Income, Line #29 Operating Revenue Requirement (line #1) minus Total Operating Expenses (line #27).

Other Income, Line #31 n/a

AFUDC, Line #32 The Projection assumes WUTC approval of an accounting order allowing PSE to capitalize as a regulatory asset the Upfront and Prepayments, and to earn PSE's allowed 8.4% return on the regulatory asset. The Projection further assumes that this return is not immediately collected in rates, but rather accumulated similar to the Allowance for Funds Used During Construction (AFUDC). While the AFUDC is a credit to income it also increases the amount in the regulatory asset account for amortization during the term of the Agreement.

Total Other Income, Line #33 Sum of other income (line #31) and AFUDC (line #32).

Income Before Interest Charges, Line #35 Sum of operating income (line # 29) plus total other income (line #33).

Interest Expense, Line #37 Interest cost is calculated as the weighted borrowing cost of short-term debt, long-term debt and trust preferred multiplied by the beginning of year ratebase (regulatory asset).

Net Income, Line #39 Income before interest (line #35) minus interest expense (line #37).

Less: Preferred Stock Dividends, Line #40 Preferred stock dividend is calculated as the weighted cost of preferred stock, 0.0034%, times beginning of year ratebase (regulatory asset).

Income for Common Stock, Line #41 Net income (line #29) minus preferred stock dividends (line #40).

<u>Ratebase Calculation</u>

Beginning Ratebase (Regulatory Asset), Line #43 Regulatory asset account equal to the ending balance from the prior year.

Upfront and Prepayment Requirement, Line #44 The District and PSE negotiated an Upfront charge of $89 million, to be paid within 30 days upon receipt of all necessary approvals by the parties.

The District requires a Prepayment sufficient to satisfy a Purchaser's payment obligations in the event a payment is not made on time as required under the proposed Power Sales Agreement or Transmission Agreement. PSE and the District have negotiated an amount equal to $18,500,000, which will be refunded to PSE, without interest, against its final power cost statement(s) at the end of the contract term.

AFUDC, Line #45 See line #32. In this line the AFUDC is added to the beginning of the year balance in the regulatory asset account.

Amortization, Line #46 See line #21. Annual regulatory asset amortization expense, which is subtracted from beginning of year ratebase.

Ending Ratebase, Line #47 Ending ratebase is the sum of beginning ratebase (line #43), plus upfront payments (line #44), plus AFUDC (line #45), minus amortization expense (line #46).

ROR (Op. Inc. on Beginning Ratebase), Line #49 Rate of Return (ROR) is the calculated return of operating income (line #29) divided by beginning of period ratebase (line #43).

Unit Cost Calculation

Operating Revenue Requirement, Line #52 Same as line #1.

Energy GWH, Line #53 Twenty five percent (25%) of expected generation from Rocky Reach, starting November 1, 2011, and Rock Island, starting July 1, 2012 (estimated annual generation derived from a refill study based on FR04-05 and adjusted for encroachment and Canadian Entitlement obligations).

PPA Cost per MWh, Line #54 Unit cost is calculated by dividing operating revenue requirement (line #52) by energy in MWh (line #53 * 1000).

Imputed Debt (S&P 30% Risk Factor), Line #56 The Standard and Poor's ("S&P") rating agency considers long-term take-or-pay contracts debt-like in nature and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Hence, there is a cost associated with issuing equity to rebalance the Company's debt/equity ratio in response to imputed debt if PSE is to maintain its current credit rating. Imputed debt is calculated using a similar methodology to that applied by S&P. The Projection assumes that income statement lines #9 through #18 are payments that S&P would treat as fixed obligations. This yearly fixed obligation is then multiplied by a 30% risk factor. Imputed debt is the sum of the present value (using a 10% discount rate and a mid-year cash flow convention) of this risk-adjusted fixed obligation.

Cost of Equity Offset, Line #57 The cost of imputed debt is the equity return on the amount of equity that would be required to offset the level of imputed debt to maintain the Company's capital and interest coverage ratios.

Unit Cost of Equity Offset \$/MWh, Line #58	Cost of equity offset to imputed debt (line #57) divided by energy in MWh (line #53 * 1000). Note: The unit cost of equity offset in 2011 and 2012 is relatively high because there is a full year of imputed debt but only a partial year of energy production from the Agreement.
Total Cost Including Equity Offset \$/MWh, Line #60	Sum of PSA Cost per MWh (line #54) plus Unit Cost of Equity Offset \$/MWh (line #58).