EXHIBIT NO. ___(JHS-8C)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: JOHN H. STORY

**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____

**SEVENTH EXHIBIT (CONFIDENTIAL) TO THE
PREFILED DIRECT TESTIMONY OF
JOHN H. STORY
ON BEHALF OF PUGET SOUND ENERGY, INC.**

**REDACTED
VERSION**

FEBRUARY 15, 2006

PSE 2006 GENERAL RATE CASE

**PROPOSED NEW AND REVISED TERMS FOR THE
POWER COST ADJUSTMENT MECHANISM (PCA)**

1. Overview of the Proposed PCA and PSE's Revisions to the Current PCA

1.1 PSE's proposed revisions to the PCA would maintain the current structure of the PCA as a mechanism that accounts for differences in PSE's modified actual power costs relative to a power cost baseline. The revised mechanism would continue to account for and share costs and benefits of power cost variances, but with a revised set of sharing bands. The revised PCA would continue to address the variability of power costs that are primarily weather or market related. In addition, it would be expanded to include "known and measurable" changes in previously approved power contracts. The revised PCA would simplify the accounting required to perform the annual PCA "true up" and to implement the sharing provided for in the PCA.

1.2 PSE would still be allowed to file for rate increases to implement power supply cost increases related to new resources and changes in market prices in "Power Cost Only" reviews that have come to be known as "power cost only rate cases" (PCORCs). The prudence of new long-term acquisitions would be reviewed and approved in the first PCORC or general rate case to be filed by PSE after any such resource acquisition.

2. Sharing proposal

2.1 Sharing Bands:

- **First Sharing Band:** $25 million (+/-) annually, 50% of costs and benefits to Customers; 50% of costs and benefits to Company.
- **Second Sharing Band:** $25 - $120 million (+/-) annually, 90% of costs and benefits to Customers; 10% of costs and benefits to Company.
- **Third Sharing Band:** greater than $120 million (+/-) annually, 95% of costs and benefits to Customers; 5% of costs and benefits to Company.

2.2 **Deferral and Interest:** The customers' share of the power cost variability will be deferred as described below, and the balance will accrue monthly interest at the interest rate calculated in accordance with WAC 480-90-233(4). Amounts will be deferred consistent with recovery under the provisions of SFAS 71.

3. Annual True-Up and Timing of Surcharges or Credits:

3.1 The sharing amounts will be accounted for on an annual basis, January 1 through December 31. The surcharging of deferrals can be triggered by the Company when the balance of the deferral account is approximately $30 million. The Company shall make a rate filing to refund deferrals when the balance in the deferral account is a credit of $30 million.

3.2 To address financial needs and to provide Customers a price signal to reduce energy consumption, a surcharge can be triggered when the Company determines that, for any upcoming 12 month period, the projected increase in the deferral balance for increased power costs will exceed $30 million. The surcharge will be implemented through a special filing subject to Commission approval detailing the events giving rise to the projected cost variance.

3.3 At the end of March each year, the Company shall file an annual report detailing the power costs included in the deferral calculation, in a form satisfactory to the Commission, for Commission review and approval. The Commission shall have an opportunity to review the prudence of new short-term (two years or less) power costs included in the deferred calculation, and costs determined to be imprudent can be disallowed at that time. Staff and other interested parties will have the opportunity to participate in the prudence review process. The Company will also provide the Commission with a quarterly report of the deferral calculation in a form satisfactory to the Commission.

3.4 Unless otherwise determined by the Commission, surcharges or credits will be collected or refunded, as the case may be, over a one year period. If for any reason the PCA shall cease to exist, any balances in the PCA deferral accounts not previously reviewed will be reviewed and set for refund or surcharge to customers at that time.

4. Elements of the Power Cost Rate

4.1 In order to focus on the component of the Company's rates to be adjusted by a PCA, it is necessary to distinguish between power costs and all other costs in general rates. This will single out the relative portion of the Company's rate to be adjusted by the proposed PCA and in periodic PCORCs. The purpose is for the PCA, and any PCORC, to measure the cost of power delivered to PSE's system, and to measure the change in this overall cost. The following table illustrates the proposed distinctions among costs in the Company's rates.

Total Revenue Requirement Table

Variable Rate Component	**Fixed Rate Component of Historic Resources**[1]	**Non-power Costs**
Fuel Other revenues and costs associated with fuel Purchase & Interchange including long-term (>2 years) power contracts Sales to Others Wheeling costs Transmission income associated with specific lines* Specific Production regulatory assets[2] amortization and allowed return (Rate of Return net of tax) at current PCA rate year level Interest expense and associated fees with hedging line of credit Adjustment for availability of Colstrip Rate Disallowances for March Point 2 & Tenaska	Production Plant and specific Transmission* Return on Ratebase (Rate of Return net of tax) Production Plant and specific Transmission Depreciation Production Plant and specific Transmission Property Taxes Production plant and specific Transmission O&M Other Power Supply Expenses	Transmission (other than what has been included in PCA fixed rate component) Distribution All other operating accounts not included in the Power Cost Rate

[1] "Production Plant" and "Transmission" related items in these columns refer to Production Plant and Transmission that was in service as of the last general rate case or PCORC. These items are to be recovered at the last general rate case or PCORC revenue levels.

* Colstrip 1&2 line, Colstrip 3&4 line. Third AC, Northern Intertie.

4.2 **Adjustment for Availability of Colstrip**: A Colstrip adjustment will be measured against a weighted equivalent availability factor. If the actual availability factor (weighted by PSE ownership times unit capacity) for the four plants at Colstrip falls below a 70% equivalent availability factor a reduction will be made to the allowable revenue requirement for Colstrip. The calculation will be calculated by subtracting the actual weighted equivalent availability factor from 75%. This difference will be divided by 75% and the resulting percentage will be multiplied times the fixed costs (such fixed costs being more particularly described in Exhibit A) associated with Colstrip. The revenue requirement associated with this portion of these fixed costs will be removed from the allowable costs in the PCA.

5. New Resources

5.1 New resources with a term of less than or equal to two years will be included in the allowable PCA costs. The prudence of these resources will be determined in the Commission's review of the annual PCA true-up report. New resources with a term greater than two years may be included in the PCA allowable cost at the lesser of the actual cost or the average embedded cost in the PCA (including transmission into PSE's Puget Sound system) as a bridge mechanism, until the then future costs of these new resources can be reviewed in a Power Cost Only Rate review.

6. Power Cost Only Rate Cases (PCORCs)

6.1 In addition to the annual adjustment for power cost variances, PSE may periodically file a proceeding specific to power costs that trues up the Power Cost Rate to *all power costs* identified in the Power Cost Rate, including changes in market prices and the costs of new resources, which is known as a "power cost only rate case" or "PCORC." This filing shall include testimony and exhibits that include the following:

- References to the current integrated resource plan (a/k/a least cost plan) as well as any such plan on which a new acquisition was based
- Description of the need for additional resources (as applicable)
- Evaluation of alternatives under various scenarios
- Adjustments to the Fixed Rate Component
- Adjustments to the Variable Rate Component

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[2] Regulatory Assets = Tenaska, Encogen (Cabot Oil buy out), Bonneville Exchange Power, White River Relicensing/CWIP, White River Plant Costs, CanWest Liability and Hopkins Ridge Prepaid Transmission.

- Support for any adjustments to the Fixed Rate Component of New Resources made since the last PCORC or general rate case

- A calculation of proforma production cost schedules that are consistent with the Company's most recent prior general rate case or PCORC, including power supply and other adjustments impacting then current production costs.

- The net of tax Rate of Return authorized in the most recent general rate case filing for the Company will be used in determining the recovery on production related assets.

- Detail of Line of Credit costs

6.2 One objective of a PCORC is to have the new Power Cost Rate in effect by the time a new resource would go into service. Upon receipt of such filing, hearings would be scheduled to review the appropriateness of adjusting the Power Cost Rate and/or adding new resource costs to the Power Cost Rate. These hearings would consider only power supply costs included within the Power Cost Rate. It is contemplated that this review would be completed within 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.

7. PCA Accounting Details and Illustrations

7.1 Exhibit A details PSE’s presentation of the power costs, on a test year level (as defined in the revenue requirement for the 2006 general rate case filing) identified in the Total Revenue Requirement Table. The purpose of this exhibit is to calculate the Power Cost Baseline Rate which is defined as the sum of the Fixed Rate Components and Variable Rate Components divided by the test year delivered load (MWh).

7.2 Exhibit B, which is based on the Company’s presentation of the PCA 3 (July 2004 through June 2005) compliance filing, is an explanation and example of a calculation used in the PCA to determine the amount of power cost that will be subject to the sharing mechanism. This exhibit calculates the amount subject to sharing by subtracting the Baseline Power Costs from the Allowed Power Costs (rate year). Baseline Power Costs are defined as the Power Cost Baseline Rate times actual delivered load in the PCA period. The allowed power costs, as shown in the Total Revenue Requirement Table in section 4, includes: return on fixed production and transmission ratebase, return on variable (regulatory asset) ratebase, other Fixed Rate Components and actual cost of variable rate components included in the specified FERC accounts. The allowed power costs are adjusted for:

- Prudence adjustment of Tenaska and March Point Phase 2 as ordered in Docket No. UE-921262.

- Prudence adjustment for Tenaska as ordered in Docket No. UE-031725

- Interest expense and associated fees with hedging line of credit

- Regulatory asset ratebase and amortization will be adjusted to the amounts to be included for the appropriate PCA period (Exhibit D)

- Exhibit E is discontinued as of January 1, 2007

- Colstrip availability adjustment if applicable (Exhibit F)

- New resource pricing adjustment if applicable (Exhibit G)

7.3 Exhibit H details clarification and methodologies for the annual PCA true up filing that were approved in PSE's annual filing for PCA Period 1, Docket No. UE-031389.

8. Rate Spread

8.1 Unless otherwise ordered by the Commission, changes in rates attributable to PCA adjustments for the Variable Rate Component shall be charged on a cents/kWh basis, and changes in rates attributable to adjustments to the Power Cost Rate as a result of a power cost only review shall be charged based upon the peak credit methodology utilized in computing the rate spread methodology in the most recent general rate case proceeding. No party is deemed to have approved or accepted these methodologies for any other purpose or precedent. Wholesale customers will be allocated power costs and power revenues at the end of a PCA year in the same relationship as done in the rate allocation from the Company's most recently concluded general rate case.

Exhibit A

Exhibit A-1 Power Cost Rate

Row		Test Year	Test Yr $/MWh		Rate Year
3	Regulatory Assets (Variable)	$ 230,034,285			
4	Transmission Rate Base (Fixed)	113,206,055			
5	Production Rate Base (Fixed)	1,002,685,953			
6		$ 1,345,926,293			Production
7	Net of tax rate of return	**7.57%**			Factor
8			**Test Yr**		0.99109
9			**$/MWh**		**Rate Year**
10	Regulatory Asset Recovery (on Row 3)	$ 26,790,147	$ 1.317	(c)	
11	Fixed Asset Recovery Other (on Row 4)	13,184,151	$ 0.648	(a)	13,184,151
12	Fixed Asset Recovery-Prod Factored (on Row 5)	116,774,349	$ 5.741	(a)	117,824,162
13	501-Steam Fuel	49,357,273	$ 2.427	(c)	
14	555-Purchased power	712,676,347	$ 35.040	(c)	
14a	Tenaska disallowance	(11,786,042)	$ (0.579)	(c)	
15	557-Other Power Exp	7,052,087	$ 0.347	(a)	7,115,486
15a	Payroll Overheads - Worker's Comp	1,077,159	$ 0.053	(a)	1,086,842
15b	Property Insurance	1,952,634	$ 0.096	(a)	1,970,189
15c	Montana Electric Energy Tax	1,704,512	$ 0.084	(a)	1,719,835
15d	Payroll Taxes on Production Wages	524,291	$ 0.026	(a)	529,004
16	547-Fuel	44,290,328	$ 2.178	(c)	
17	565-Wheeling	60,298,381	$ 2.965	(c)	
18	Variable Transmission Income	(3,869,746)	$ (0.190)	(c)	
19	Hydro and Other Pwr.	73,832,956	$ 3.630	(a)	74,496,722
20	447-Sales to Others	(10,163,628)	$ (0.500)	(c)	
21	456-Subaccounts 00012 & 00018 and 00035 & 00036	(470,768)	$ (0.023)	(c)	
22	Transmission Exp - 500KV	862,248	$ 0.042	(a)	870,000
23	Depreciation & Amort -Production (FERC 403)	68,076,116	$ 3.347	(a)	68,688,127
24	Depreciation-Transmission	5,109,174	$ 0.251	(a)	5,109,174
25	Amortization-Production Reg Assets	30,028,391	$ 1.476	(c)	
26	Property Taxes-Production	12,693,942	$ 0.624	(a)	12,808,062
27	Property Taxes-Transmission	4,237,062	$ 0.208	(a)	4,237,062
28	Cost of Hedging Facility			(c)	
29	Subtotal & Baseline Rate	$ 1,204,231,365	**$ 59.208**	(b)	309,638,818
30	Revenue Sensitive Items	0.9549744			
31		$ 1,261,009,074			
32	Test Year DELIVERED Load (MWH's)	20,339,227	<-- includes Firm Wholesale		
33					
34					
35					
36		Before Rev.	After Rev.		
37		Sensitive Items	Sensitive Items		
38	Power Cost in Rates with Revenue Sensitive				
39	Items (the adjusted baseline)	$ 59.208	$ 62.000		
40	sum of (a) = Fixed Rate Component	$ 15.097	$ 15.809		
41	(b) = Power Cost Rate	$ 59.208	$ 62.000		
42	sum of (c) = Variable Power Rate Component	$ 44.111	$ 46.191		

Exhibit A-2 Transmission Rate Base

Row				Plant AMA 9/30/2005	AMA Accum Deprec/Amort	Net	Annualized Depreciation
8							
9							
6			TRANS - COLSTRIP 1 & 2				
7	E350	100428	Land and Land Rights	$ 10,247	$ -	$ 10,247	$ -
8	E351	100127	Easements	685,927	(328,174)	357,753	17,011
9	E353	100136	Station Equipment	1,231,131	(809,116)	422,015	34,964
10	E354	100145	Towers & Fixtures	14,474,343	(7,330,817)	7,143,526	374,889
11	E355	100149	Poles & Fixtures	49,007	(43,744)	5,263	774
12	E356	100157	OH Conductors & Devices	13,158,153	(7,143,515)	6,014,638	369,744
13	E359	100170	Roads & Trails	113,968	(54,580)	59,388	2,872
14		TOTAL COLSTRIP 1&2 TRANSMISSION		29,722,776	(15,709,946)	14,012,830	800,254
15							
16			TRANS - COLSTRIP 3 & 4				
17	E351	100128	Easements	1,071,124	(498,101)	573,023	27,314
18	E352	100132	Structures & Improvements	496,711	(235,088)	261,623	12,132
19	E353	100137	Station Equipment	17,948,341	(8,791,003)	9,157,338	586,329
20	E354	100146	Towers & Fixtures	20,492,882	(10,042,410)	10,450,472	543,826
21	E355	100150	Poles & Fixtures	88,692	(50,835)	37,857	2,386
22	E356	100158	OH Conductors & Devices	19,991,226	(10,587,643)	9,403,583	571,749
23	E359	100171	Roads & Trails	341,015	(160,200)	180,815	8,730
24		TOTAL COLSTRIP 3&4 TRANSMISSION		60,429,991	(30,365,280)	30,064,711	1,752,466
25							
26			TRANS - 3RD NW-SW INTERTIE				
27	E350	100430	Land and Land Rights	1,769,178	-	1,769,178	-
28	E352	100134	Structures & Improvements	1,276,264	(274,257)	1,002,007	22,845
29	E353	100143	Station Equipment	31,157,075	(8,339,518)	22,817,557	716,613
30	E354	100147	Towers & Fixtures	22,781,417	(4,958,160)	17,823,257	430,569
31	E355	100649	Poles & Fixtures	204,200	(40,881)	163,319	5,268
32	E356	100164	OH Conductors & Devices	23,458,256	(6,895,149)	16,563,107	609,915
33	E356	100437	OH Conductors & Devices	206	(32)	174	5
34	E359	100174	Roads & Trails	59,215	(6,495)	52,720	628
35		TOTAL 3RD NW-SW INTERTIE		80,705,811	(20,514,492)	60,191,319	1,785,843
36							
37			TRANS - NORTHERN INTERTIE				
38	E350	100881	Land and Land Rights	30,604	-	30,604	-
39	E354	100879	Towers & Fixtures-Whatcom	5,744,097	(956,614)	4,787,483	106,840
40	E355	100878	Poles & Fixtures-Whatcom	11,219	(3,305)	7,914	289
41	E356	100877	OH Conductors & Devices-Whatcom	7,460,099	(1,672,921)	5,787,178	193,963
42	E355	100647	Poles & Fixtures-Skagit	3,398,685	(767,764)	2,630,921	87,686
43	E356	100648	OH Conductors & Devices-Skagit	5,142,699	(1,020,137)	4,122,562	133,710
44		TOTAL NORTHERN INTERTIE		21,787,403	(4,420,741)	17,366,662	522,488
45							
46							
47	Total Transmission			$ 192,645,981	$ (71,010,459)	$ 121,635,522	$ 4,861,051
48	Accumulated Depreciation (AMA)			(71,010,459)			
49	Deferred Taxes (AMA)			(13,194,608)			
50	Transmission portion of:						
51	Colstrip Common FERC Adj, net of accum amort			4,101,699			213,630
52	Colstrip Def Depr FERC Adj, net of accum amort			663,442			34,493
53							
54	Total Transmission Rate Base			$ 113,206,055			$ 5,109,174

Exhibit A-3 Colstrip Fixed Costs

Row	Revenue Requirement for Colstrip			
3	Plant	685,685,332		
4	Accumulated Depreciation	(390,462,218)		
5	Deferred Taxes - AMA 9/30/2005	(65,389,156)		
6	Net Plant	229,833,958		A-3 Page 1
7	Rate of Return (net of Tax)	7.57%		
8	Revenue Requirement after tax	17,398,431	(Line 6 X Line 7)	
9	Plant Revenue Requirement	26,766,816	(Adjusted for Federal Tax) (Line 8 X (1 - 35%))	35.00%
10	Expenses	55,944,269		
11	Total Revenue Requirement	82,711,085	(before revenue sensitive items)	
12				
13	Support for Revenue Requirement - Ratebase			

14	FERC	DESCRIPTION	2004/Sep	2005 Sep	13 MONTH AMA	ANNUITY RATE	ANNUALIZED DEPRECIATION	ACUMM. DEPR. 09/30/2005
15		COLSTRIP #1						
16	E311	Structures & Improvements	7,404,108	7,372,745	7,379,192	3.03%	223,590	(4,421,280)
17	E312	Boiler Plant Equipment	52,330,034	58,845,150	54,774,956	3.12%	1,708,979	(36,229,045)
18	E314	Turbo Generating Units	14,755,278	14,969,912	14,892,838	3.29%	489,974	(9,142,691)
19	E315	Accessory Electric Equipment	7,152,369	7,153,656	7,153,283	2.71%	193,854	(5,233,999)
20	E316	Misc. Power Plant Equipment	496,853	537,632	526,541	3.87%	20,377	(298,785)
21		TOTAL	82,138,642	88,879,094	84,726,810	3.11%	2,636,774	(55,325,800)
22		COLSTRIP #2						
23	E311	Structures & Improvements	5,730,076	5,727,592	5,728,023	3.06%	175,278	(4,045,437)
24	E312	Boiler Plant Equipment	46,840,522	46,553,042	46,537,700	3.05%	1,419,400	(30,518,549)
25	E314	Turbo Generating Units	14,480,769	14,323,040	14,314,565	3.26%	466,655	(8,318,739)
26	E315	Accessory Electric Equipment	5,304,326	5,061,164	5,111,718	2.69%	137,505	(3,107,857)
27	E316	Misc. Power Plant Equipment	518,105	562,410	550,585	3.61%	19,876	(298,108)
28		TOTAL	72,873,798	72,227,249	72,242,591	3.07%	2,218,714	(46,288,690)
29		COLSTRIP 1 & 2 COMMON						
30	E311	Structures & Improvements	31,473,984	31,359,809	31,383,595	3.16%	991,722	(22,516,690)
31	E312	Boiler Plant Equipment	8,354,764	8,030,614	8,098,146	3.18%	257,521	(6,033,870)
32	E314	Turbo Generating Units	3,918,858	3,918,858	3,918,858	3.31%	129,714	(2,914,004)
33	E315	Accessory Electric Equipment	2,420,179	2,379,882	2,388,277	3.07%	73,320	(1,595,736)
34	E316	Misc. Power Plant Equipment	6,365,234	6,365,234	6,365,234	3.82%	243,152	(4,001,768)
35	E317	Asset Retirement Obligation	540,097	540,097	540,097	0.00%	-	(401,214)
36		TOTAL	53,073,116	52,594,494	52,694,207	3.22%	1,695,429	(37,463,282)
37		COLSTRIP 3						
38	E311	Structures & Improvements	28,988,443	28,976,803	28,979,169	2.45%	709,990	(17,082,932)
39	E312	Boiler Plant Equipment	119,104,734	120,861,355	119,259,726	2.68%	3,196,161	(72,579,648)
40	E314	Turbo Generating Units	37,846,094	38,223,363	38,124,264	2.97%	1,132,291	(18,249,215)
41	E315	Accessory Electric Equipment	6,466,260	6,466,260	6,466,260	2.47%	159,717	(3,543,352)
42	E316	Misc. Power Plant Equipment	502,407	531,119	523,297	2.86%	14,966	(261,991)
43		TOTAL	192,907,938	195,058,900	193,352,716	2.70%	5,213,125	(111,717,138)
44		COLSTRIP 4						
45	E311	Structures & Improvements	26,558,346	26,546,706	26,549,072	2.54%	674,346	(14,408,437)
46	E312	Boiler Plant Equipment	105,422,962	105,620,134	105,567,131	2.75%	2,903,096	(55,979,740)
47	E314	Turbo Generating Units	32,479,545	33,040,130	32,872,602	2.94%	966,454	(14,524,657)
48	E315	Accessory Electric Equipment	5,660,702	5,660,702	5,660,702	2.52%	142,650	(2,761,989)
49	E316	Misc. Power Plant Equipment	700,012	728,727	720,904	2.79%	20,113	(354,593)
50		TOTAL	170,821,567	171,596,400	171,370,411	2.75%	4,706,659	(88,029,417)
51		COLSTRIP 3 & 4 COMMON						
52	E311	Structures & Improvements	70,723,992	70,625,143	70,674,528	2.33%	1,646,717	(41,266,676)
53	E312	Boiler Plant Equipment	20,359,928	19,413,895	19,610,986	2.48%	486,352	(11,412,510)
54	E314	Turbo Generating Units	277,420	277,420	277,420	2.62%	7,268	(156,203)
55	E315	Accessory Electric Equipment	7,748,971	7,669,926	7,686,394	2.31%	177,556	(4,098,397)
56	E316	Misc. Power Plant Equipment	4,725,430	4,725,430	4,725,430	2.79%	131,839	(2,420,718)
57	E317	Asset Retirement Obligation	333,978	333,978	333,978	0.00%	-	(197,349)
58		TOTAL	104,169,719	103,045,792	103,308,736	2.37%	2,449,732	(59,551,852)
59		COLSTRIP 1-4 COMMON						
60	E316	Misc. Power Plant Equip.	251,534	251,534	251,534	2.46%	6,188	(149,670)
61		TOTAL	251,534	251,534	251,534	2.46%	6,188	(149,670)
62								
63	Subtotal before Colstrip FERC Adjustments (Line 63 + 65)		676,236,313	683,653,463	677,947,005	2.79%	18,926,621	(398,525,849)
64	ARO - Electric Colstrip 1-4 (Acct: 23001021 - 1031) Adj (AMA is Net of Accum. Amort.)				(1,741,100)		(61,406)	
65	Colstrip Common FERC Adj. (AMA is Net of Accum. Amort.)				6,809,639		354,669	
66	Colstrip Def Depr FERC Adj. (AMA is Net of Accum. Amort.)				2,669,788		104,311	
67		Total Plant and Acc. Deprec.			685,685,332	2.82%	19,324,194	(398,525,849)
68								
69			AMA Adj. to Accum Depr.					8,063,631
70			Totals		685,685,332	2.82%	19,324,194	(390,462,218)

Exhibit A-3 Colstrip Fixed Costs

ROW			
71			
72			
73			
74			
75	Support for Revenue Requirement - Expenses		
76			**Amount before**
77	Order	Description	**Prod. Adj.**
78	50004011	1&2 Sup & Eng - Steam Ope	$ XXXXXXXX
79	50004012	1&2 Sup & Eng - Steam Ope	$ XXXXXXXX
80	50005011	3&4 Sup & Eng - Steam Ope	$ XXXXXXXX
81	50005012	3&4 Sup & Eng - Steam Ope	$ XXXXXXXX
82	50204001	1&2 Steam Exp - Steam Gen Op	$ XXXXXXXX
83	50205001	3&4 Steam Exp - Steam Gen Op	$ XXXXXXXX
84	50504001	1&2 Elec Exp - Steam Gen	$ XXXXXXXX
85	50505001	3&4 Elec Exp - Steam Gen	$ XXXXXXXX
86	50604001	1&2 Misc Exp - Steam Gen	$ XXXXXXXX
87	50605001	3&4 Misc Exp - Steam Gen	$ XXXXXXXX
88	50605002	3&4 Steam - Housing	$ XXXXXXXX
89	50704001	1&2 Rents - Steam Gen Oper	$ XXXXXXXX
90	50705001	3&4 Rents - Steam Gen Oper	$ XXXXXXXX
91	51004001	1&2 Maint Supv - Steam Gen	$ XXXXXXXX
92	51005001	3&4 Maint Supv - Steam Gen	$ XXXXXXXX
93	51104001	1&2 Maint of Struct - Stm Gen	$ XXXXXXXX
94	51105001	3&4 Maint of Struct - Stm Gen	$ XXXXXXXX
95	51204001	1&2 Maint of Boiler - Stm Gen	$ XXXXXXXX
96	51205001	3&4 Maint of Boiler - Stm Gen	$ XXXXXXXX
97	51304001	1&2 Maint of E Plant - Stm G	$ XXXXXXXX
98	51305001	3&4 Maint of E Plant - Stm G	$ XXXXXXXX
99	51404001	1&2 Maint of Misc - Stm Gen	$ XXXXXXXX
100	51405001	3&4 Maint of Misc - Stm Gen	$ XXXXXXXX
101		Subtotal on Orders	25,691,710
102		Property Taxes-Montana	9,208,529
103		Electric Energy Tax	1,719,835
104	403xxxxx	Depreciation	19,324,194
105			$ 55,944,269

REDACTED VERSION

Exhibit A-4 Production Adjustment

PUGET SOUND ENERGY
PRODUCTION ADJUSTMENT
FOR TWELVE MONTHS ENDED SEPTEMBER 30, 2005
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	PROFORMA AND RESTATED	PRODUCTION 0.891%	FIT 35%
1	**O&M ON PRODUCTION PROPERTY**			
2	PRODUCTION WAGE INCREASE:			
3	PURCHASED POWER	$ 61,809	$ (551)	$ 193
4	OTHER POWER SUPPLY	283,215	(2,523)	883
5	TOTAL PRODUCTION WAGE INCREASE	345,024	(3,074)	1,076
6				
7	WIND PLANT POWER COSTS AND PRODUCTION O&M:			
8	565 - WHEELING	2,728,405	(24,310)	8,509
9	PRODUCTION O&M	14,650,354	(130,535)	45,687
10	TOTAL WILD HORSE POWER COSTS AND PRODUCTION O&M	17,378,759	(154,845)	54,196
11				
12	ADMIN & GENERAL EXPENSES			
13	PAYROLL OVERHEADS	1,086,842	(9,684)	3,389
14	PROPERTY INSURANCE	1,970,189	(17,554)	6,144
15	TOTAL ADMIN & GENERAL EXPENSES	3,057,031	(27,238)	9,533
16				
17	DEPRECIATION / AMORTIZATION:			
18	DEPRECIATION	65,700,547	(585,392)	166,941
19	AMORTIZATION	2,987,580	(26,619)	8,194
20	TOTAL DEPRECIATION AND AMORTIZATION (FERC 403)	68,688,127	(612,011)	175,136
21	TAXES OTHER-PRODUCTION PROPERTY:			
22	PROPERTY TAXES - WASHINGTON	6,957,804	(61,994)	21,698
23	PROPERTY TAXES - MONTANA	5,850,258	(52,126)	18,244
24	ELECTRIC ENERGY TAX	1,719,835	(15,324)	5,363
25	PAYROLL TAXES	529,004	(4,713)	1,650
26	TOTAL TAXES OTHER	15,056,901	(134,157)	46,955
27				
28	**O&M ON REGULATORY ASSETS:**			
29	CABOT	$ 3,078,000	$ (27,425)	$ 9,599
30	TENASKA	24,343,000	(216,896)	75,914
31	BEP	3,526,620	(31,422)	10,998
32	WHITE RIVER PLANT COSTS	1,494,702	(13,318)	4,661
33	WHITE RIVER RELICENSING & CWIP	-	-	-
34	CANWEST	(3,797,503)	33,836	(11,843)
35	HOPKINS RIDGE PREPAID TRANSMISSION	1,653,530	(14,733)	5,157
36	TOTAL ADJUSTMENT TO O&M ON REGULATORY ASSETS	$ 30,298,349	$ (269,958)	$ 94,486
37	INCREASE(DECREASE) EXPENSE		(1,201,284)	
38	INCREASE(DECREASE) FIT			381,382
39	INCREASE(DECREASE) NOI			$ 819,902
40				
41	**PRODUCTION PROPERTY RATE BASE:**			
42	DEPRECIABLE PRODUCTION PROPERTY	$ 1,699,912,438	$ (15,146,220)	
43	LESS PRODUCTION PROPERTY ACCUM DEPR.	(664,968,132)	5,924,866	
44	NON-DEPRECIABLE PRODUCTION PROPERTY	51,671,468	(460,393)	
45	LESS PRODUCTION PROPERTY ACCUM AMORT.	(3,018,492)	26,895	
46	COLSTRIP COMMON FERC ADJUSTMENT	6,809,639	(60,674)	
47	COLSTRIP DEFERRED DEPRECIATION FERC ADJ.	2,006,346	(17,877)	
48	ENCOGEN ACQUISITION ADJUSTMENT	46,646,833	(415,623)	
49	NET PRODUCTION PROPERTY	1,139,060,099	(10,149,025)	
50	DEDUCT:			
51	LIBR. DEPREC. PRE 1981 (EOP)	(669,177)	5,962	
52	LIBR. DEPREC. POST 1980 (EOP)	(122,639,761)	1,092,720	
53	OTHER DEF. TAXES (EOP)	(4,050,958)	36,094	
54	SUBTOTAL	(127,359,896)	1,134,777	
55				
56	ADJUSTMENT TO PRODUCTION RATE BASE	$ 1,011,700,203	$ (9,014,249)	$ 1,002,685,955
57				
58	**REGULATORY ASSETS RATE BASE:**			
59	CABOT	2,824,963	(25,170)	
60	TENASKA	142,925,042	(1,273,462)	
61	BEP	24,007,413	(213,906)	
62	WHITE RIVER PLANT COSTS	39,052,307	(347,956)	
63	WHITE RIVER RELICENSING & CWIP	17,018,469	(151,635)	
64	CANWEST	(2,468,377)	21,993	
65	HOPKINS RIDGE PREPAID TRANSMISSION	8,742,500	(77,896)	
66				
67	ADJUSTMENT TO REGULATORY ASSETS RATE BASE	$ 232,102,317	$ (2,068,032)	$ 230,034,285
68				
69	TOTAL ADJUSTMENT TO RATEBASE (LINE 56 + LINE 67)		$ (11,082,282)	

Exhibit A-5 Power Costs

PUGET SOUND ENERGY
POWER COSTS
FOR TWELVE MONTHS ENDED SEPTEMBER 30, 2005
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	ACTUAL	PROFORMA	INCREASE (DECREASE)
1	SALES FOR RESALE	$ 151,158,328	$ 10,163,628	$ (140,994,700)
2				
3	PURCHASES/SALES OF NON-CORE GAS	20,154,644	470,768	(19,683,876)
4	WHEELING FOR OTHERS	11,340,015	10,373,140	(966,875)
5		31,494,659	10,843,908	(20,650,751)
6				
7	**TOTAL OPERATING REVENUES**	**182,652,987**	**21,007,536**	**(161,645,451)**
8				
9	FUEL	$ 72,975,508	$ 93,647,602	$ 20,672,094
10				
11	PURCHASED AND INTERCHANGED	788,255,330	719,667,176	(68,588,154)
12	RATE DISALLOWANCES FOR MARCH POINT 2	-	(11,786,042)	(11,786,042)
13	SUBTOTAL PURCHASED AND INTERCHANGE	$ 788,255,330	$ 707,881,134	$ (80,374,196)
14	WHEELING	43,994,427	57,594,286	13,599,859
15	SCH. 94 - RES./FARM CREDIT	(177,350,021)	-	177,350,021
16	TOTAL PRODUCTION EXPENSES	$ 727,875,244	$ 859,123,021	$ 131,247,777
17	HYDRO AND OTHER POWER	53,185,137	59,032,445	5,847,308
18	TRANS. EXP. INCL. 500KV O&M	604,461	862,248	257,787
19				
20	**TOTAL OPERATING EXPENSES**	**$ 781,664,842**	**$ 919,017,715**	**$ 137,352,873**
21				
22	INCREASE (DECREASE) OPERATING INCOME	$ (599,011,855)	$ (898,010,179)	$ (298,998,324)
23				
24	REDUCTION TO STATE UTILITY TAX SAVING	3.85%		(37,225)
25	INCREASE (DECREASE) INCOME			$ (298,961,099)
26	INCREASE (DECREASE) FIT @	35%		(104,636,385)
27	INCREASE (DECREASE) NOI			$ (194,324,715)

Exhibit B

******* New Line 22 Added to PCA 3 Compliance Filing Schedule B as an Example of where the new variable cost line item would be reported for purposes of calculating the imbalance for sharing. *******

PCA Mechanism Annual Report-PCA 3
Twelve Months Ended June 30, 2005

Schedule B: Monthly Power Costs -- PCA PERIOD 3
Derived from Original PCA Exhibit B
Subject to PCA Sharing

Row				Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Period to Date
6																
7	Return on Fixed RB	See Note 1		$ 5,952,602	$ 5,952,602	$ 5,952,602	$ 5,952,602	$ 5,952,602	$ 5,952,602	$ 5,952,602	$ 5,952,602	$ 5,410,395	$ 5,352,302	$ 5,352,302	$ 5,352,302	$ 69,088,116
8	Other Fixed Costs	See Note 1		10,375,599	10,375,599	10,375,599	10,375,599	10,375,599	10,375,599	10,375,599	10,375,599	10,510,357	10,524,795	10,524,795	10,524,795	$ 125,089,534
9	Subtotal Fixed Costs	See Note 1		$ 16,328,201	$ 16,328,201	$ 16,328,201	$ 16,328,201	$ 16,328,201	$ 16,328,201	$ 16,328,201	$ 16,328,201	$ 15,920,752	$ 15,877,097	$ 15,877,097	$ 15,877,097	$ 194,177,650
10	Total Variable Component Actual	FERC Acct.														
11	Steam Oper. Fuel	501		$ 3,288,599	$ 3,480,552	$ 3,610,969	$ 3,463,020	$ 3,325,277	$ 3,476,529	$ 3,503,854	$ 2,965,708	$ 3,421,975	$ 3,820,872	$ 3,452,860	$ 3,528,002	$ 41,338,218
12	Other Pwr Gen Fuel	547		5,284,453	5,992,443	3,634,557	2,772,513	3,579,636	4,022,996	5,288,247	3,115,691	2,152,905	595,630	1,012,788	483,423	37,935,282
13	Other Elec Revenues	45600012,18,35,36,80,81,130		(332,534)	(834,237)	(426,827)	(1,496,649)	(1,338,366)	(3,047,856)	(1,245,557)	(1,096,991)	(1,818,019)	(1,278,151)	289,729	11,429	(12,614,029)
14	Purchase Power	555		48,883,934	45,829,621	42,885,051	57,063,867	64,223,110	79,463,886	77,458,519	67,011,387	70,646,023	60,527,650	39,998,545	55,109,664	709,101,258
15	Sales to Other Util	447		(5,830,696)	(6,542,999)	(4,184,103)	(3,607,314)	(4,871,974)	(9,239,491)	(7,265,134)	(3,691,222)	(5,364,563)	(4,981,063)	(3,969,640)	(7,919,760)	(67,467,959)
16	Wheeling	565		3,410,410	3,571,738	3,572,097	3,532,623	3,416,831	3,671,000	3,426,574	2,963,424	3,147,921	4,039,969	3,695,695	3,597,563	42,045,845
17	Transmission Revenue	45600017		(120,482)	(118,471)	(129,934)	(473,842)	(451,927)	(517,107)	(450,165)	(434,022)	(495,764)	(338,062)	(1,024,166)	(221,978)	(4,775,920)
18	WR Amort and DIT turnaround for Reg Assets (See Note 2)			124,559	124,559	124,559	124,559	124,559	124,559	124,559	124,559	(2,326)	(15,920)	(15,920)	(15,920)	946,381
19	Subtotal Variable Components			$ 54,708,243	$ 51,503,206	$ 49,086,369	$ 61,378,777	$ 68,007,146	$ 77,954,516	$ 80,840,897	$ 70,958,534	$ 71,688,152	$ 62,370,925	$ 43,439,891	$ 54,572,423	$ 746,509,076
20																
21	Regulatory Assets (Return on RB portion only)			2,740,363	2,740,363	2,740,363	2,740,363	2,730,469	2,730,469	2,730,469	2,730,469	2,767,685	2,771,672	2,771,672	2,771,672	$ 32,966,029
22	Interest Cost on Hedging Facility															
23	**SUBTOTAL before Adjustments**			$ 73,776,806	$ 70,571,769	$ 68,154,933	$ 80,447,341	$ 87,065,816	$ 97,013,185	$ 99,899,566	$ 90,017,203	$ 90,376,589	$ 81,019,694	$ 62,088,660	$ 73,221,192	$ 973,652,756
24																
25	**Adjustments:**															
26	Prudence from UE-921262			$ (246,552)	$ (240,477)	$ (239,479)	$ (260,876)	$ (262,229)	$ (279,097)	$ (273,795)	$ (246,096)	$ (280,508)	$ (167,856)	$ (141,354)	$ (239,815)	$ (2,878,134)
27	Contract price adjustment			(12,111)	(11,977)	8,933	(8,164)	(13,361)	8,805	590	(204)	(338)	(62,221)	33,773	(7,139)	(63,414)
28	Colstrip availability adjustment			-												
29	Frederickson #1 True-up Adjustment			-	3,126.83	1,563.42	1,563.42	1,563.42	(7,817.00)							
30	Tenaska Disallowance (prior month adj)															
31	Tenaska Disallowance (current month adj)			$ (945,641)	$ (945,641)	$ (945,641)	$ (945,641)	$ (945,641)	$ (945,641)	$ (945,641)	$ (945,641)	$ (876,383)	$ (850,275)	$ (850,275)	$ (850,275)	$ (10,992,337)
32																-
33	Subtotal Adjustments			$ (1,204,304)	$ (1,194,968)	$ (1,174,624)	$ (1,213,118)	$ (1,219,668)	$ (1,223,750)	$ (1,218,846)	$ (1,191,941)	$ (1,157,229)	$ (1,080,352)	$ (957,856)	$ (1,097,229)	$ (13,933,885)
34	**Total allowable cost (line 28/line 30) (Before Tenaska adj)**			$ 72,572,502	$ 69,376,801	$ 66,980,310	$ 79,234,223	$ 85,846,149	$ 95,789,435	$ 98,680,720	$ 88,825,262	$ 89,219,360	$ 79,939,341	$ 61,130,803	$ 72,123,963	$ 959,718,871
35																
36																
37	PCA period delivered load (Kwh)			1,505,672,925	1,518,220,896	1,438,527,629	1,613,588,029	1,818,690,442	2,029,607,929	2,062,784,766	1,805,488,208	1,762,054,643	1,613,522,425	1,510,083,013	1,449,457,451	20,127,698,356
38	**Baseline Power Cost**															
39		5/24/04 - 3/04/05	$0.046303	$ 69,717,173	$ 70,298,182	$ 66,608,145	$ 74,713,967	$ 84,210,824	$ 93,976,936	$ 95,513,123	$ 83,599,520	7,895,653				646,533,523
39a		3/4/05 - 6/30/05	$0.049132									78,195,210	$ 79,275,584	$ 74,193,399	$ 71,214,743	302,878,936
41	Imbalance for Sharing			$ 2,855,329	$ (921,381)	$ 372,165	$ 4,520,257	$ 1,635,325	$ 1,812,499	$ 3,167,597	$ 5,225,742	$ 3,128,496	$ 663,758	$ (13,062,595)	$ 909,220	$ 10,306,412
42	positive is potential customer surcharge, negative is potential customer credit			$ 2,855,329	$ (921,381)	$ 372,165	$ 4,520,257	$ 1,635,325	$ 1,812,499	$ 3,167,597	$ 5,225,742	$ 3,128,496	$ 663,758	$ (13,062,595)	$ 909,220	$ 10,306,412
43																
44			Jul-Feb Mar-May													
45	**Less Firm Wholesale**		0.0404% 0.0398%	$ 2,854,174	$ (921,008)	$ 372,014	$ 4,518,429	$ 1,634,664	$ 1,811,766	$ 3,166,316	$ 5,223,628	$ 3,127,248	$ 663,494	$ (13,057,396)	$ 908,858	$ 10,302,187
46	**Gross PCA**			$ 2,854,174	$ (921,008)	$ 372,014	$ 4,518,429	$ 1,634,664	$ 1,811,766	$ 3,166,316	$ 5,223,628	$ 3,127,248	$ 663,494	$ (13,057,396)	$ 908,858	$ 10,302,187
47	**Gross PCA Contra**			$ (2,854,174)	$ 921,008	$ (372,014)	$ (4,518,429)	$ (1,634,664)	$ (1,811,766)	$ (3,166,316)	$ (5,223,628)	$ (3,127,248)	$ (663,494)	$ 13,057,396	$ (908,858)	$ (10,302,187)
48																
49	**Cumulative Gross PCA**			$ 2,854,174	$ 1,933,166	$ 2,305,180	$ 6,823,608	$ 8,458,272	$ 10,270,039	$ 13,436,355	$ 18,659,983	$ 21,787,232	$ 22,450,725	$ 9,393,329	$ 10,302,187	$ 10,302,187
50	**Cumulative Gross PCA Contra**			$ (2,854,174)	$ (1,933,166)	$ (2,305,180)	$ (6,823,608)	$ (8,458,272)	$ (10,270,039)	$ (13,436,355)	$ (18,659,983)	$ (21,787,232)	$ (22,450,725)	$ (9,393,329)	$ (10,302,187)	$ (10,302,187)
51																
52																
53	**Note: This schedule was derived from original PCA collaborative exhibit B**															
54	**Note 1: Fixed costs 7/04-2/05 are per PCORC Exhibit A-1, 4/05-6/05 are per GRC, 3/05 is blended 3 days PCORC and 28 days GRC**															
55	**Note 2: White River for entire PCA period and DIT turnaround for all reg assets beginning with GRC 3.4.05.**															

Provided for Illustrative Purposes Only

Exhibit C

Exhibit C would no longer be relevant with removal of $40 million cap

Exhibit D

Exhibit D: Regulatory Assets and Liabilities
PCA PERIODS - FILED WITH THE 2006 GRC

			12 Months Ended December 31		PCA Periods - 12 Months Ended June 30 and / or Dcember 31					
				Balance net of		AMA Ratebase		Return		
Ref	Description		Asset Amort	AA	Asset Amort	Net of DFIT	As of	A.T. %	After Tax	Pre Tax
						(Note 1)				
8										
9	**Cabot Buyout**				G/L Accts #18230171,19000121 and #28300461 and Order #54756002, 54756012					
10	Beginning	$		14,565,000						
11	Dec 2000	$	(312,000)	14,253,000						
12	Dec 2001	$	(741,000)	13,512,000						
13	Dec 2002	$	(1,070,000)	12,442,000						
14	Dec 2003	$	(1,409,000)	11,033,000						
15	Dec 2004	$	(1,768,000)	9,265,000						
16	Dec 2005	$	(2,163,000)	7,102,000						
17	Dec 2006	$	(2,614,000)	4,488,000	(2,388,500)	5,766,541	6/06	7.01%	404,235	621,899
18					(1,307,000)	4,842,106	12/06	7.01%	169,716	261,101
19	Dec 2007	$	(3,078,000)	1,410,000	(3,078,000)	2,823,371	12/07	7.57%	213,729	328,814
20	Dec 2008	$	(1,410,000)	-	(1,410,000)	687,449	12/08	7.57%	52,040	80,061
23										
24										
25	**Tenaska**				G/L Accts #18230001 and #28300451 and Order #55500423					
26	Beginning	$		215,000,000						
27	Dec 1998	$	(1,952,000)	221,802,000						
28	Dec 1999	$	(3,863,000)	226,734,000						
29	Dec 2000	$	(5,463,000)	230,120,000						
30	Dec 2001	$	(7,382,000)	231,576,000						
31	Dec 2002	$	(9,494,000)	228,644,000						
32	Dec 2003	$	(11,924,000)	216,720,000						
33	Dec 2004	$	(14,744,000)	201,976,000						
34	Dec 2005	$	(17,908,000)	184,068,000						
35	Dec 2006	$	(20,615,000)	163,453,000	(19,261,500)	174,037,125	6/06	7.01%	12,200,002	18,769,235
36					(10,307,500)	164,680,500	12/06	7.01%	5,772,052	8,880,079
37	Dec 2007	$	(24,343,000)	139,110,000	(24,343,000)	142,925,000	12/07	7.57%	10,819,423	16,645,265
38	Dec 2008	$	(28,272,000)	110,838,000	(28,272,000)	118,181,500	12/08	7.57%	8,946,340	13,763,599
39	Dec 2009	$	(32,676,000)	78,162,000	(32,676,000)	89,519,500	12/09	7.57%	6,776,626	10,425,579
40	Dec 2010	$	(37,533,000)	40,629,000	(37,533,000)	56,502,000	12/10	7.57%	4,277,201	6,580,310
41	Dec 2011	$	(40,629,000)	-	(40,629,000)	19,647,750	12/11	7.57%	1,487,335	2,288,207
42	Dec 2012	$	-	-	-	-	12/12	7.57%	-	-
43	Dec 2013	$	-	-	-	-	12/13	7.57%	-	-
44										
45										

Exhibit D: Regulatory Assets and Liabilities
PCA PERIODS - FILED WITH THE 2006 GRC

			12 Months Ended December 31		PCA Periods - 12 Months Ended June 30 and / or Dcember 31					
				Balance net of		AMA Ratebase		Return		
Ref	Description		Asset Amort	AA	Asset Amort	Net of DFIT	As of	A.T. %	After Tax	Pre Tax
						(Note 1)				
46										
47	**BEP**				G/L Accts #18230071, 18230081, 28300431 and Order #55500007					
48	Beginning			$54,662,561						
49	Dec 2002	$	(3,526,620)	51,135,941						
50	Dec 2003	$	(3,526,620)	47,609,321						
51	Dec 2004	$	(3,526,620)	44,082,701						
52	Dec 2005	$	(3,526,620)	40,556,081						
53	Dec 2006	$	(3,526,620)	37,029,461	(3,526,620)	40,556,081	6/06	7.01%	2,842,981	4,373,817
54					(1,763,310)	38,792,771	12/06	7.01%	1,359,687	2,091,826
55	Dec 2007	$	(3,526,620)	33,502,841	(3,526,620)	24,007,413	12/07	7.57%	1,817,361	2,795,940
56	Dec 2008	$	(3,526,620)	29,976,221	(3,526,620)	21,608,793	12/08	7.57%	1,635,786	2,516,593
57	Dec 2009	$	(3,526,620)	26,449,601	(3,526,620)	19,210,173	12/09	7.57%	1,454,210	2,237,246
58	Dec 2010	$	(3,526,620)	22,922,981	(3,526,620)	16,811,553	12/10	7.57%	1,272,635	1,957,899
59	Dec 2011	$	(3,526,620)	19,396,361	(3,526,620)	14,412,933	12/11	7.57%	1,091,059	1,678,552
60	Dec 2012	$	(3,526,620)	15,869,741	(3,526,620)	12,014,313	12/12	7.57%	909,483	1,399,205
61	Dec 2013	$	(3,526,620)	12,343,121	(3,526,620)	9,615,693	12/13	7.57%	727,908	1,119,858
62	Dec 2014	$	(3,526,620)	8,816,501	(3,526,620)	7,217,073	12/14	7.57%	546,332	840,511
63	Dec 2015	$	(3,526,620)	5,289,881	(3,526,620)	4,818,453	12/15	7.57%	364,757	561,164
64	Dec 2016	$	(3,526,620)	1,763,261	(3,526,620)	2,419,833	12/16	7.57%	183,181	281,817
65	Dec 2017	$	(1,763,261)	0	(1,763,261)	309,550	12/17	7.57%	23,433	36,051
66	Dec 2018	$	-	0	-	-	12/18	7.57%	-	-
67										
68										
69	**White River Relicensing (Note 2)**				G/L Accts #18230641, #18230691, #19000021 and 28300011					
70	Beginning	$		20,545,452						
71	Dec 2004	$		17,943,372						
72	Dec 2005	$		19,767,073						
73	Dec 2006	$		19,767,073	-	16,555,219	6/06	7.01%	1,160,521	1,785,417
74					-	17,018,469	12/06	7.01%	596,497	917,688
75	Dec 2007	$		19,767,073	-	17,018,469	12/07	7.57%	1,288,298	1,981,997
76	Dec 2008	$		19,767,073	-	17,018,469	12/08	7.57%	1,288,298	1,981,997
77	Dec 2009	$		19,767,073	-	17,018,469	12/09	7.57%	1,288,298	1,981,997
78	Dec 2010	$		19,767,073	-	17,018,469	12/10	7.57%	1,288,298	1,981,997
79	Dec 2011	$		19,767,073	-	17,018,469	12/11	7.57%	1,288,298	1,981,997
80										
81										

Exhibit D: Regulatory Assets and Liabilities
PCA PERIODS - FILED WITH THE 2006 GRC

			12 Months Ended December 31		PCA Periods - 12 Months Ended June 30 and / or Dcember 31					
				Balance net of		AMA Ratebase		Return		
Ref	Description		Asset Amort	AA	Asset Amort	Net of DFIT	As of	A.T. %	After Tax	Pre Tax
						(Note 1)				
82										
83	**White River Plant Costs**				G/L Accts #18220011, #18220021, #18220031, #18220041 and #18220051 and Order #40700015					
84	Beginning	$		47,882,224	DFIT included in 28200121					
85	Dec 2004	$	(1,494,702)	46,383,414						
86	Dec 2005	$	(1,494,702)	44,888,677						
87	Dec 2006	$	(1,494,702)	43,393,975	(1,494,702)	40,834,092	6/06	7.01%	2,862,470	4,403,800
88					(747,351)	40,229,603	12/06	7.01%	1,410,048	2,169,304
89	Dec 2007	$	(1,494,702)	41,899,273	(1,494,702)	39,052,307	12/07	7.57%	2,956,260	4,548,092
90	Dec 2008	$	(1,494,702)	40,404,572	(1,494,702)	37,907,451	12/08	7.57%	2,869,594	4,414,760
91	Dec 2009	$	(1,494,702)	38,909,870	(1,494,702)	36,762,057	12/09	7.57%	2,782,888	4,281,366
92	Dec 2010	$	(1,494,702)	37,415,168	(1,494,702)	35,644,106	12/10	7.57%	2,698,259	4,151,167
93	Dec 2011	$	(1,494,702)	35,920,466	(1,494,702)	34,533,160	12/11	7.57%	2,614,160	4,021,785
94										
95										
96	**Canwest Liability**				G/L Accts #25400021, #14300061 and 19000451 and Order # 54756014					
97	Beginning	$		-						
98	Dec 2004	$	-	(1,503,528)						
99	Dec 2005	$	632,917	(9,493,757)						
100	Dec 2006	$	3,797,503	(5,696,254)	2,215,210	(5,490,031)	6/06	7.01%	(384,851)	(592,079)
101					1,898,751	(4,936,754)	12/06	7.01%	(173,033)	(266,205)
102	Dec 2007	$	3,797,503	(1,898,751)	3,797,503	(2,468,377)	12/07	7.57%	(186,856)	(287,471)
103	Dec 2008	$	1,898,751	-	1,898,751	(308,547)	12/08	7.57%	(23,357)	(35,934)
104	Dec 2009	$	-	-	-	-	12/09	7.57%	-	-
105										
106										
107	**Hopkins Ridge**				G/L Accts #18230231, Order #56500101					
108	Beginning	$		10,750,000						
109	Dec 2005	$	-	10,750,000						
110	Dec 2006	$	(1,194,328)	9,555,672	(411,866)	6,662,434	6/06	7.01%	276,383	425,205
111					(782,461)	10,293,120	12/06	7.01%	360,774	555,037
112	Dec 2007	$	(1,653,530)	7,902,142	(1,653,530)	8,742,500	12/07	7.57%	661,807	1,018,165
113	Dec 2008	$	(1,816,192)	6,085,951	(1,816,192)	7,008,603	12/08	7.57%	530,551	816,233
114	Dec 2009	$	(1,990,698)	4,095,253	(1,990,698)	5,106,186	12/09	7.57%	386,538	594,674
115	Dec 2010	$	(2,177,843)	1,917,410	(2,177,843)	3,023,011	12/10	7.57%	228,842	352,065
116	Dec 2011	$	(1,917,410)	-	(1,917,410)	790,244	12/11	7.57%	59,822	92,033
117										

Exhibit D: Regulatory Assets and Liabilities
PCA PERIODS - FILED WITH THE 2006 GRC

		12 Months Ended December 31		PCA Periods - 12 Months Ended June 30 and / or Dcember 31					
			Balance net of		AMA Ratebase		Return		
Ref	Description	Asset Amort	AA	Asset Amort	Net of DFIT	As of	A.T. %	After Tax	Pre Tax
					(Note 1)				

Ref	Total all Regulatory Assets and Liabilities				AMA Ratebase		Pre-Tax Return		
	Period	From	To	Asset Amort	Net of DFIT	As of	A.T. %	Amount	Monthly
124	PCA 4	Jul-05	Jun-06	(24,867,978)	278,921,461	6/06	7.01%	29,787,294	2,482,274
125	PCA 4-5	Jul-06	Dec-06	(13,008,871)	270,919,815	12/06	7.01%	14,608,830	1,217,403
126	PCA 5	Jan-07	Dec-07	(30,298,349)	232,100,683	12/07	7.57%	27,030,803	2,252,567
127	PCA 6	Jan-08	Dec-08	(34,620,762)	202,103,718	12/08	7.57%	23,537,310	1,961,442
128	PCA 7	Jan-09	Dec-09	(39,688,019)	167,616,385	12/09	7.57%	19,520,862	1,626,739
129	PCA 8	Jan-10	Dec-10	(44,732,165)	128,999,139	12/10	7.57%	15,023,438	1,251,953
130	PCA 9	Jan-11	Dec-11	(47,567,732)	86,402,556	12/11	7.57%	10,062,575	838,548

Note (1) Amounts in these columns are net of accumulated amortization AND the associated Deferred FIT liabilitiy / asset. DFIT balances are end of period balances through December 2006 and average of the monthly averages thereafter.

Note (2) During the 2004 General Rate Case filed under WUTC Docket No. UE-040640, et al., it was agreed that the return of the White River Relicensing costs would be delayed until the sale of White River is complete. At that time, the Commission can make a final determination in a separate proceeding regarding the application of the proceeds against the deferred costs and the disposition of any remaining balance.

Exhibit E

Exhibit E has been eliminated under proposed revised PCA Mechanism

Exhibit F

********* Exhibit F - Colstirp Availability Adjustment - Example provided from the Exhibit accepted in the PCA Period 3 Compliance Filing WUTC Docket No. UE-051314 *********

Schedule F - Colstrip Availability Adjustment

Derived from Original PCA Exhibit F

UE-011570

Row

5 **Part 1. Colstrip Equivalent Availability during PCA period -12 Month**

Row		1&2	3&4			PSE Wtd	PSE Wtd	PSE Wtd	PSE Wtd	PSE Wtd	PSE Wtd	PSE Wtd	PSE Wtd	PSE Wtd	PSE Wtd	PSE Wtd	PSE Wtd
8	PSE MW Capacity ->	307	370	PSE Wtd	days	**Jul-04**	**Aug-04**	**Sep-04**	**Oct-04**	**Nov-04**	**Dec-04**	**Jan-05**	**Feb-05**	**Mar-05**	**Apr-05**	**May-05**	**Jun-05**
9	**Jul-04**	86.50%	82.30%	84.2%	31	95.31%	95.19%	93.72%	86.29%	90.69%	93.55%	93.58%	96.80%	77.58%	69.43%	73.18%	84.20%
10	Aug-04	98.50%	85.30%	91.3%	31	95.19%	93.72%	86.29%	90.69%	93.55%	93.58%	96.80%	77.58%	69.43%	73.18%	84.20%	91.29%
11	Sep-04	92.50%	86.90%	89.4%	30	93.72%	86.29%	90.69%	93.55%	93.58%	96.80%	77.58%	69.43%	73.18%	84.20%	91.29%	89.44%
12	Oct-04	88.10%	96.30%	92.6%	31	86.29%	90.69%	93.55%	93.58%	96.80%	77.58%	69.43%	73.18%	84.20%	91.29%	89.44%	92.58%
13	Nov-04	89.70%	93.90%	92.0%	30	90.69%	93.55%	93.58%	96.80%	77.58%	69.43%	73.18%	84.20%	91.29%	89.44%	92.58%	92.00%
14	Dec-04	93.10%	93.40%	93.3%	31	93.55%	93.58%	96.80%	77.58%	69.43%	73.18%	84.20%	91.29%	89.44%	92.58%	92.00%	93.26%
15	Jan-05	88.70%	96.80%	93.1%	31	93.58%	96.80%	77.58%	69.43%	73.18%	84.20%	91.29%	89.44%	92.58%	92.00%	93.26%	93.13%
16	Feb-05	94.10%	92.90%	93.4%	28	96.80%	77.58%	69.43%	73.18%	84.20%	91.29%	89.44%	92.58%	92.00%	93.26%	93.13%	93.44%
17	Mar-05	82.30%	83.00%	82.7%	31	77.58%	69.43%	73.18%	84.20%	91.29%	89.44%	92.58%	92.00%	93.26%	93.13%	93.44%	82.68%
18	Apr-05	86.40%	91.50%	89.2%	30	69.43%	73.18%	84.20%	91.29%	89.44%	92.58%	92.00%	93.26%	93.13%	93.44%	82.68%	89.19%
19	May-05	51.60%	97.10%	76.5%	31	73.18%	84.20%	91.29%	89.44%	92.58%	92.00%	93.26%	93.13%	93.44%	82.68%	89.19%	76.47%
20	Jun-05	71.50%	88.90%	81.0%	30	84.20%	91.29%	89.44%	92.58%	92.00%	93.26%	93.13%	93.44%	82.68%	89.19%	76.47%	81.01%
21																	
22	12 mo Average	85.18%	90.68%	**88.18%**		**87.42%**	**87.21%**	**86.76%**	**86.58%**	**87.04%**	**87.20%**	**87.22%**	**87.17%**	**85.98%**	**86.91%**	**87.55%**	**88.18%**
23	Weighted by days in the month		Weighted by Plant Capacity and days/month														

26 **Part 2. Calculate annual availability penalty ratio**

Row				Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05
27	Less than 70%	no	no penalty assessed	no	no	no	no	no	no	no	no	no	no	no	no
28	Actual Ratio	88.18%		87.42%	87.21%	86.76%	86.58%	87.04%	87.20%	87.22%	87.17%	85.98%	86.91%	87.55%	88.18%
29	Target Ratio	75.00%	per Collaborative agreement	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%
30	Penalty	0.00%	no penalty if actual ratio >= 70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	Penalty Ratio =	0.00%	= penalty 0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34			divided by 75.00% per Collaborative agreement												

37 **Part 3. Calculate Annual Colstrip Fixed Cost Penalty**

Row				Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
39	Total Fixed Cost	$ 77,514,634	from Exhibit A-3 (Colstrip Total Revenue Require	77,514,638	77,514,638	77,514,638	77,514,638	77,514,638	77,514,638	77,514,638	77,514,638	77,514,638	77,514,638	77,514,638	77,514,638
41	Penalty Ratio =	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
42	**Penalty $**	**$ -**	**to Exhibit B line 25**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43				**Mo_Cols_Jul**	**Mo_Cols_Aug**	**Mo_Cols_Sep**	**Mo_Cols_Oct**	**Mo_Cols_Nov**	**Mo_Cols_dec**	**Mo_Cols_Jan**	**Mo_Cols_Feb**	**Mo_Cols_Mar**	**Mo_Cols_Apr**	**Mo_Cols_May**	**Mo_Cols_Jun**
44	Penalty Monthly	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

46 **Note: This schedule was derived from original PCA collaborative exhibit F**

Exhibit G

******** Exhibit G - New Resource Adjustment - Example provided from WUTC Docket No. UE-011570 and UG-011571 Exhibit A to the Settlement Stipulation ********

Exhibit G - New Resource Adjustment

Row				
7	**For New Resources with a Terms Longer than 2 Years**			
8				
9	**Name**	Sample new plant		
10	**Description**	Combined cycle gas turbine		
11		In-service date January 2003		
12				
13				
14	**PCA Period**	July 2002 - June 2003		
15				
17	**Total Variable Component Actual**			
18	Steam Oper. Fuel	501	$	-
19	Other Pwr Gen Fuel	547		33,000,000
20	Other Elec Revenues	45600012, 18		-
21	Purchase Power	555		-
22	Sales to Other Util	447		-
23	Wheeling	565		750,000
24	Transmission Revenue	45600017		-
25			$	33,750,000
26				
27	PCA Period Generation	(MWh)		750,000
28				
29	**Actual Variable Cost**	**($/MWh)**		**$45.000**
30	Compare with Baseline Rate			
31				
32	**Baseline Power Cost Rate**	**($/MWh)**		**$44.482**
33				
34	**Lesser of Actual Cost or Baseline Rate**			
35	Baseline Power Cost Rate			$44.482
36				
37	**Adjustment Needed?**		**Yes**	
38	Adjustment needed if Baseline rate is lower than actual variable cost			
39				
40	Adjustment Rate	($/MWh)		-$0.518
41	Adjustment volume	(MWh)		750,000
42	**Adjustment Amount**	($)	**$**	**(388,500)** to Exhibit B line 24

Provided for illustrative purposes only

Exhibit H

Methodology for Adjustments of Costs Outside of the PCA Period

A. Adjustments for Costs prior to July 1, 2002:

Power cost entries, true-ups and adjustments posted in the current month for months prior to the beginning of the PCA, July 1, 2002, will be excluded from power costs in the monthly PCA calculation. Note the exceptions in item D., below.

B. Adiustments for Costs Recorded After Termination of PC A Mechanism:

Power cost adjustments posted in the month following the termination of the PCA Mechanism relating to the PCA periods will be included in power costs for the month of the final PCA calculation and the deferral will be adjusted accordingly. Note the exceptions in item D., below.

C. Adjustments for Previous PCA Periods:

1. Power cost adjustments or true-ups for prior periods that fall within the PCA mechanism period (July 1,2002 forward) are included as recoverable power costs under the PCA mechanism. Adjustments for previous PCA periods that are equal to or less than $1 million (debit or credit) will flow through the current month PCA calculation. Note the exceptions in item D below.

2. Adjustments or true-ups greater than $1 million (5% of the $20 million 'deadband' from the original PCA Mechamism) (debit or credit) that relate to prior PCA periods will be flowed through a recalculation of the previous PCA period for regulatory purposes. Any changes to the customer deferrals from the prior PCA period will be indicated in a reconciliation schedule for deferrals by PCA period. Note the exceptions in item D., below.

D. Exceptions:

Exceptions will be made for items A, B and C adjustments for the following power costs:

1. Company Accounting Errors:
For all accounting errors made by the Company, except for Colstrip fuel costs, if an error has been made in regard to accounting for power cost transactions, to the extent that the Company should have known at the time of the transaction, the Company will reflect the appropriate adjustment to the appropriate PCA period(s) and adjust the deferral for the period (s) accordingly.

2. Mid-Columbia Power Costs:
PSE books debt and O&M expense as billed from the Mid-Columbia Public Utility Districts, each dam is identified below. Current month power cost expense equal the current month debt service cost plus an estimate of actual O&M costs. This estimation is calculated differently for different Dams. PSE does not accrue for estimated true-ups to monthly O&M billed costs.

Subsequent to the PUD's annual audits, PSE receives a bill or credit for any prior year adjustments. For example, Chelan PUD (Rocky Reach & Rock Island I & II) operates on a calendar year and audit true ups are normally received in May of the following year.

Since it is difficult to determine to what month(s) the annual true-ups actually impact, audit true-ups for the MidC projects should be treated as debits or credits in the PCA period those adjustments are normally found, see below. If the annual true-ups are booked in a month, other than that listed below, which causes them to be recorded in a different PCA period, then the treatment of adjustments as identified in item C above apply. These annual true-ups include the Douglas County PUD Settlement Agreement that is typically a credit.

Normal true up periods for PSE Mid Columbia resources
Priest Rapids and Wanapum are trued-up in April for the prior calendar year.
Rocky Reach and Rock Islands 1 and 2 are trued-up in May for the prior calendar year.
Wells, the year ended August is trued-up in the following months, September through December.

3. Colstrip Fuel Costs
   Monthly fuel costs represent the tonnage burned at the embedded inventory unit cost. Inventory cost represents commodity charges, royalties, reclamation accruals and true-ups from prior periods for all these types of costs. Coal inventory costs include prior period adjustments as well as corrections of accounting errors due to the difficulty in determining what period of costs are included in the beginning and ending inventory balances. Therefore, no adjustments will be made for Colstrip inventory valuation for prior period adjustments, and any true-ups or corrections from prior periods will be included in power costs at the time they become known. Adjustments for prior periods that meet the criteria in item C will be adjusted for regulatory purposes outside of the inventory valuation process.