

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of

PUGET SOUND ENERGY, INC.

For Approval of its 2006 Power Cost Adjustment
Mechanism Report

Docket No. UE-_____

EXHIBIT A TO THE PETITION OF
PUGET SOUND ENERGY, INC.
FOR APPROVAL OF ITS 2006 POWER
COST ADJUSTMENT MECHANISM
ANNUAL REPORT

**Settlement Stipulation, as revised by the 15th Supplemental Order in
WUTC Docket No. UE-011570, et al.**

Exhibit A to Petition of
Puget Sound Energy, Inc. For
Approval Of Its 2006 Power Cost
Adjustment Mechanism Annual Report

**Exhibit A to
Settlement Stipulation**

**PSE GENERAL RATE CASE
DOCKET NOS. UE-011570 and UG-011571**

**SETTLEMENT TERMS FOR THE
POWER COST ADJUSTMENT MECHANISM (PCA)**

A. Executing Parties

1. The following parties have participated in the Power Cost Adjustment mechanism (PCA) collaborative in Docket Nos. UE-011570 and UG-011571, and have reached consensus on the terms of settlement with respect to such issues, as set forth in this Agreement: Puget Sound Energy, Inc. ("PSE" or the "Company"); the Staff of the Washington Utilities and Transportation Commission; the Public Counsel Section of the Attorney General's Office; Intervenor the Kroger Co.; Intervenor AT&T Wireless Services, Inc.; Intervenor NW Energy Coalition and Natural Resources Defense Council; Federal Executive Agencies; and Intervenor Cogeneration Coalition of Washington (hereinafter referred to collectively as "Executing Parties").

B. Overview of PCA

2. The proposed PCA is a mechanism that would account for differences in PSE's modified actual power costs relative to a power cost baseline. This mechanism would account for a sharing of costs and benefits that are graduated over four levels of power cost variances, with an overall cap of \$40 million (+/-) over the four year period July 1, 2002 through June 30, 2006. If the cap is exceeded, costs and benefits in excess of \$40 million would be shared at a different level of sharing. The factors influencing the variability of power costs included in the proposal are primarily weather or market related. PSE will be allowed to file for rate increases to implement limited power supply cost increases related to new resources, discussed later.

3. **Sharing proposal:**

- **First Band (dead band):** \$20 million (+/-) annually, 100% of costs and benefits to Company.
- **Second Sharing Band:** \$20-\$40 million (+/-) annually, 50% of costs and benefits to Company; 50% of costs and benefits to Customers.

- **Third Sharing Band:** \$40-\$120 million (+/-) annually, 10% of costs and benefits to Company, 90% of costs and benefits to Customers.
- **Fourth Sharing Band:** Greater than \$120 million (+/-) annually, 5% of costs and benefits to Company; 95% of costs and benefits to Customers.
- **Overall Cap For Four Year Period July 1, 2002 through June 30, 2006:** As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed above. If this cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to Customers and 1% of costs and benefits to Company. The cap is removed at end of the fourth year (June 30, 2006), and any deferred balances associated with the cap are set for refund or collection at that time.
- **Deferral and Interest:** The customer's 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.

4. **Timing of surcharges or credits:**

- The sharing amounts will be accounted for, on an annual basis. The first 12 month period will be the period beginning July 1, 2002 and ending June 30, 2003. Subsequent PCA periods will be 12 month period beginning on July 1 of each year. 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 filing to refund deferrals when the balance in the deferral account is a credit of \$30 million or more.
- 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.
- In August of 2003 and each year thereafter, 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 the 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.

- 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 deferred accounts not previously reviewed will be reviewed and set for refund or surcharge to customers at that time.

C. Elements of PCA

5. **Power Cost Rate:** 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 the periodic "Power Cost Only" review. The purpose is for the PCA, and any Power Cost Only case, 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

Total Rate		
Power Cost Rate¹		Non-power Costs
Variable Rate Component	Fixed Rate Component	
<p>Fuel</p> <p>Other revenues and costs associated with fuel</p> <p>Purchase & Interchange (purchase power contracts not to exceed general rate case or PCA resource case cost level)</p> <p>Sales to Others</p> <p>Wheeling costs</p> <p>Transmission income associated with specific lines</p> <p>Specific Production regulatory assets* amortization and return (7.30% net of tax) at current PCA rate year level</p> <p>Adjustment for availability of Colstrip</p>	<p>Following items to be recovered at the last general rate case or PCA resource case revenue levels:</p> <p>Production Plant and specific Transmission** Return on Ratebase (7.30% net of tax)</p> <p>Production Plant and specific Transmission Depreciation</p> <p>Production Plant and specific Transmission Property Taxes</p> <p>Production plant and specific Transmission O&M</p> <p>Other Power Supply Expenses</p> <p>**Specific Transmission – Colstrip 1&2 line, Colstrip 3&4 line. Third AC, Northern Intertie,</p>	<p>Transmission (other than what has been included in PCA fixed rate component)</p> <p>Distribution</p> <p>All other operating accounts not included in the Power Cost Rate.</p>
<p>*Regulatory Assets – Tenaska, Encogen (Cabot Oil buy out), Bonneville</p>	<p>**Specific Transmission – Colstrip 1&2 line, Colstrip 3&4 line. Third AC, Northern</p>	

¹ References in table correspond to FERC accounts to be itemized in the Exhibits. For example, "Other Power Supply Expenses" corresponds to FERC Account 557.

Exchange Power	Intertie,	
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6. **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.

7. **New Resources:** 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 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.

8. **Power Cost Only Rate Review:** In addition to the yearly adjustment for power cost variances, there would be a periodic proceeding specific to power costs that would true up the Power Cost Rate to *all power costs* identified in the Power Cost Rate. The Company can also initiate a power cost only proceeding to add new resources to the Power Cost Rate. In either case, the Company would submit a Power Cost Only Rate filing proposing such change. This filing shall include testimony and exhibits that include the following:

- Current or updated least cost plan
- 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
- A calculation of proforma production cost schedules that are consistent with this docket, including power supply and other adjustments impacting then current production costs.

9. If, during the first three (3) years after new rates have gone into effect (i.e., the three year period commencing July 1, 2002 and ending July 1, 2005) the Commission shall approve a cumulative increase to general rates in excess of 5%, and such cumulative increase in excess of 5% is the result of rate increases sought by the Company and approved by the Commission in one or more such Power Cost Only reviews, then within three (3) months of the date such cumulative rate increase in excess of 5% shall take effect, the Company shall file a general rate case.

10. Further, if at any time after July 1, 2005 the Company shall file for a Power Cost Only review, and such filing shall result in an increase to general rates then in effect, the Company shall, within three (3) months of the effective date of any rate increase resulting from such Power Cost Only review, file a general rate case. Not more than one general rate case filing in any 12 month period shall be required to comply with this requirement.

11. One objective of a new resource proceeding is to have the new Power Cost Rate in effect by the time the 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.

D. PCA Mechanism (procedures)

12. Exhibit A details PSE's presentation of the power costs, on a test year level (as defined in the revenue requirement settlement in Docket No. UE-011570) 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). The remaining Executing Parties agree to PSE's presentation shown in Exhibit A and will verify in due course the accuracy of the specific numbers in that exhibit.

13. Exhibit B, which is based on the Company's presentation of test year costs and is subject to verification by the remaining Executing Parties as described above, 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 include: 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:

- existing (Docket No. UE-921262) prudence adjustment of Tenaska and March Point Phase 2
- regulatory asset ratebase and amortization will be adjusted to the amounts to be included for the appropriate PCA period (Exhibit D)
- purchase power contracts will be adjusted to the amounts allowed in either the settlement Docket No. UE-011570 or the most recent Power Cost Rate Case (Exhibit E)
- Colstrip availability adjustment if applicable (Exhibit F)
- New resource pricing adjustment if applicable (Exhibit G)

14. Exhibit C is an example that demonstrates the sharing and application of the \$40 million cap.

15. 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 this 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 this docket.

E. Least-Cost Planning/Decoupling

16. One of Puget Sound Energy's important responsibilities involves electric-resource portfolio development, a responsibility addressed in the Company's least cost plans prepared pursuant to WAC 480-100-238. This includes, among other things, assembling a mix of demand-and supply-side resources that promotes the societal benefits of reliable least cost electricity supplies. The parties agree that PSE's least-cost planning process provides an appropriate forum to address the evaluation of PSE's portfolio development, including consideration of rewards and/or penalties tied to PSE's overall long-term performance in portfolio development. The parties recommend that the Commission address these issues as soon as possible in Puget's least-cost planning process, pursuant to WAC 480-100-238, with opportunities for public comment prior to final determination.

17. Nothing in this settlement precludes any party from raising in an appropriate future Commission proceeding issues surrounding the decoupling of distribution fixed cost recovery from retail sales volumes. The parties have reached no consensus on what constitutes an "appropriate proceeding" for this purpose, and reserve the right to oppose any effort to raise such issues.

F. Miscellaneous Provisions

18. **Binding on Parties:** The Executing Parties agree to support the terms and conditions of this Agreement, as described above. The Executing Parties understand that this Agreement is subject to Commission approval.

19. **Integrated Terms of Settlement:** The Executing Parties have negotiated this Agreement as an integrated document. Accordingly, the Executing Parties agree to recommend that the Commission adopt this Agreement in its entirety.

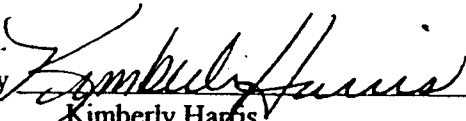
20. **Negotiated Agreement:** This Agreement represents a fully negotiated agreement. Each Executing Party has been afforded the opportunity, which it has exercised, to review the terms of the Agreement. Each Party has been afforded the opportunity, which it has exercised, to consult with legal counsel of its choice concerning such terms and their implications. The Agreement shall not be construed for or against any Executing Party based on the principle that ambiguities are construed against the drafter.

21. **Execution:** This Agreement may be executed by the Executing Parties in several counterparts, through original and/or facsimile signature, and as executed shall constitute one agreement.

DATED this 4th day of June, 2002.

PUGET SOUND ENERGY, INC.

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION
STAFF**

By 
Kimberly Harris
Vice President of Regulatory Affairs

By _____
Robert Cedarbaum
Shannon Smith
Assistant Attorneys General

**PUBLIC COUNSEL SECTION, OFFICE
OF THE ATTORNEY GENERAL OF
THE STATE OF WASHINGTON**

AT&T WIRELESS SERVICES, INC.

By _____
Simon fitch
Assistant Attorney General
Public Counsel Section Chief

By _____
Its _____

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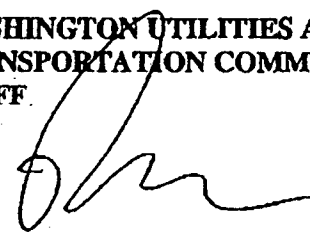
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By _____ 6/6/02
Simon Fitch
Assistant Attorney General
Public Counsel Section Chief

By _____
Its _____

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Settlement Stipulation, as revised by the 15th Supplemental Order in WUTC Docket No. UE-011570

Exhibit A to Petition of Puget Sound Energy, Inc. Page 11 of 30

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Simon Mitchell
Assistant Attorney General
Public Counsel Section Chief

By Chris Calver, C.F.M.
Its Community Manager

**COGENERATION COALITION OF
WASHINGTON**

KROGER CO.

By Donald Brookhyser

Donald Brookhyser
Attorney for Cogeneration
Coalition of Washington

By _____

Michael L. Kurtz
Attorney for Kroger Co.

**NW ENERGY COALITION and
NATURAL RESOURCES DEFENSE
COUNCIL**

By _____

Danielle Dixon
Policy Associate, NW Energy Coalition

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Page 13 of 30

MICROSOFT CORPORATION

AT&T WIRELESS SERVICES, INC.

By _____
Its _____

By _____
Its _____

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KROGER CO.

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Coalition of Washington

By Michael L. Kurtz
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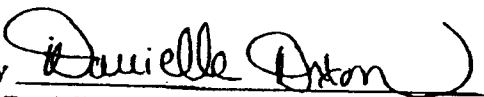
By 
Danielle Dixon
Policy Associate, NW Energy Coalition

Exhibit A-1 Power Cost Rate

Row		Test Year		
3	Regulatory Assets (Variable)	\$	284,728,294	
4	Transmission Rate Base (Fixed)		124,643,364	
5	Production Rate Base (Fixed)		493,777,165	
6		\$	903,148,823	
7	Net of tax rate of return		7.30%	
8				
9			Test Yr	Rate Year
			\$/MWh	
10	Regulatory Asset Recovery	\$	31,977,178	\$ 1.677 (c)
11	Fixed Asset Recovery-Prod Factored		54,142,951	\$ 2.840 (a)
12	Fixed Asset Recovery Other		15,310,432	\$ 0.803 (a)
13	501-Steam Fuel		32,511,186	\$ 1.705 (c)
14	555-Purchased power		526,980,333	\$ 27.643 (c)
15	557-Other Power Exp		11,499,089	\$ 0.603 (a)
16	547-Fuel		61,173,325	\$ 3.209 (c)
17	565-Wheeling		41,435,360	\$ 2.174 (c)
18	Variable Transmission Income		(6,510,985)	\$ (0.342) (c)
19	Hydro and Other Pwr.		51,597,583	\$ 2.707 (a)
20	447-Sales to Others		(37,525,193)	\$ (1.968) (c)
	456-Subaccounts 00012 & 00018 and 00035 & 00036		1,077,379	\$ 0.057 (c)
22	Transmission Exp - 500KV		342,495	\$ 0.018 (a)
23	Depreciation-Production		36,265,740	\$ 1.902 (a)
24	Depreciation-Transmission		4,851,654	\$ 0.254 (a)
25	Property Taxes-Production		8,343,174	\$ 0.438 (a)
26	Property Taxes-Transmission		4,441,860	\$ 0.233 (a)
27	Subtotal & Baseline Rate	\$	837,913,560	\$ 43.953 (b)
28	Revenue Sensitive Items		0.9552337	
29		\$	877,181,741	8,343,174
30	Test Year Load (MWH's)		19,063,867	<- includes Firm Wholesale
31			<u>Before Rev. Sensitive Items</u>	<u>After Rev. Sensitive Items</u>
32	Power Cost in Rates with Revenue Sensitive Items (the adjusted baseline			46.013
33	sum of (a) = Fixed Rate Component		9.798	10.257
34	(b) = Power Cost Rate		43.953	46.013
35	sum of (c) = Variable Power Rate Component		34.155	35.756
36				
37				
38	* Regulatory Assets are Tenaska, Encogen Fuel Buyout and BEP			
39				
40				
41				
42				
43				

Exhibit A-2 Transmission Costs

Row		Date	DR (CR) Accumulated Deferred Income Income Tax Balance			
8	Colstrip Related Transmission Assets					
9						
10	Balance at:	06/30/2001		(15,759,774)		
11	No deferred income taxes associated with the 3rd AC Intertie,					
12	Northern Intertie and BPA Transmission Assets.					
13						
14	Test Period Property Taxes on transmission Related Assets:					
15			Amount			
16	Oregon-3rd AC Intertie		\$864,624			
17	Montana-Transmission Assets		1,622,875			
18	Montana-Beneficial Use Property Taxes on BPA					
19	Transmission Assets		1,826,626			
20	Washington-Northern Intertie		127,735			
21	Total Property Taxes		\$4,441,860			
22						
23	Wheeling Expense		41,435,360			
24						
25	Transmission Plant					
26			Plant			
27			AMA 6/30/01	Accum. Dep.	Depreciation Exp.	
28	E351	TRANS - COLSTRIP 1 & 2	Easements	685,927	264,280	17,011
29	E353	Station Equipment	1,231,131	682,186	34,964	
30	E354	Towers & Fixtures	14,474,343	5,917,036	374,885	
31	E355	Poles & Fixtures	49,007	39,834	774	
32	E356	OH Conductors & devices	13,158,153	5,749,080	369,744	
33	E359	Roads & Trails	113,968	43,839	2,872	
34	COLSTRIP 1&2 TRANSMISSION		29,712,529	12,696,255	800,250	
35						
36		TRANS - COLSTRIP 3 & 4				
37	E351	Easements	1,071,124	396,585	27,314	
38	E352	Structures & Improvements	478,326	188,636	11,719	
39	E353	Station Equipment	17,687,015	6,706,154	578,365	
40	E354	Towers & Fixtures	20,422,516	8,020,387	541,197	
41	E355	Poles & Fixtures	122,619	58,220	3,298	
42	E356	OH Conductors & Devices	20,015,734	8,474,189	572,450	
43	E359	Roads & Trails	341,015	127,820	8,730	
44	COLSTRIP 3&4 TRANSMISSION		60,138,349	23,971,991	1,743,073	
45						
46		TRANS - 3RD NW-SW INTERTIE				
47	E352	Structures & Improvements	1,276,264	183,547	22,845	
48	E353	Station Equipment	31,157,075	5,529,150	716,613	
49	E354	Towers & Fixtures	22,781,417	3,276,322	430,569	
50	E355	Poles & Fixtures	204,200	19,787	5,268	
51	E356	OH Conductors & devices	23,458,461	4,528,227	609,920	
52	E359	Roads & Trails	59,215	4,141	628	
53	TOTAL 3RD NW-SW INTERTIE		78,936,632	13,541,174	1,785,843	
54						
55		TRANS - NORTHERN INTERTIE				
56	E351	Easements - Whatcom				
57	E354	Towers & Fixtures-Whatcom	5,744,097	533,604	106,840	
58	E355	Poles & Fixtures-Whatcom	11,219	1,702	289	
59	E356	OH Conductors & Devices-Whatc	7,460,099	904,353	193,963	
60	E355	Poles & Fixtures-Skagit	3,398,685	416,680	87,686	
61	E356	OH Conductors & Devices-Skagit	5,142,699	501,239	133,710	
62	TOTAL NORTHERN INTERTIE		21,756,799	2,357,577	522,488	
63						
64	Total Transmission		190,544,309	52,566,998	4,851,654	
65	Less					
66	Accumulated Depreciation		52,566,998			
67	Deferred Taxes		15,759,774			
68	Transmission Ratebase		122,217,537			
	revised_A2	revised accumulated depreciation	50,141,171			
			124,643,364			

Exhibit A-3 Colstrip Fixed Costs

Row

Revenue Requirement for Colstrip

A-3 Page 1

4	Plant	650,197,157	
5	Accumulated Depreciation	(320,264,159)	
6	Deferred Taxes	(93,634,221)	
7	Net Plant	<u>236,298,777</u>	
8	Rate of Return (net of Tax)	7.30%	
9	Revenue Requirement after tax	17,249,811	
10	Plant Revenue Requirement	26,538,170	(Adjusted for Federal Tax)
11	Expenses	<u>52,329,884</u>	
12	Total Revenue Requirement	<u>78,868,054</u>	(before revenue sensitive items)

Support for Revenue Requirement - Ratebase

FERC	DESCRIPTION	30-Jun-00	30-Jun-01	13 MONTH AMA	ANNUITY RATE	ANNUALIZED DEPRECIATION	ACUMM. DEPR. 06/30/2001
COLSTRIP #1							
E311	Structures & Improvements	6,931,939	7,097,390	7,021,558	3.03%	212,753	4,519,382
E312	Boiler Plant Equipment	46,965,650	48,224,007	47,159,778	3.12%	1,471,385	30,962,573
E314	Turbo Generating Units	12,437,937	12,437,937	12,437,937	3.29%	409,208	8,005,683
E315	Accessory Electric Equip.	7,042,053	7,043,604	7,042,893	2.71%	190,862	4,440,864
E316	Misc. Power Plant Equip.	365,117	426,565	398,402	3.87%	15,418	215,987
	TOTAL	<u>73,742,696</u>	<u>75,229,503</u>	<u>74,060,568</u>	<u>3.11%</u>	<u>2,299,626</u>	<u>48,144,488</u>
COLSTRIP #2							
E311	Structures & Improvements	5,317,757	5,573,640	5,456,360	3.06%	166,965	3,343,898
E312	Boiler Plant Equipment	39,821,935	40,460,296	40,167,714	3.05%	1,225,115	26,457,593
E314	Turbo Generating Units	12,178,755	12,519,462	12,363,305	3.26%	403,044	7,691,610
E315	Accessory Electric Equip.	4,536,518	4,592,474	4,566,828	2.69%	122,848	2,797,275
E316	Misc. Power Plant Equip.	365,931	427,379	399,215	3.61%	14,412	217,888
	TOTAL	<u>62,220,895</u>	<u>63,573,251</u>	<u>62,953,422</u>	<u>3.07%</u>	<u>1,932,384</u>	<u>40,508,264</u>
COLSTRIP 1 & 2 COMMON							
E311	Structures & Improvements	30,345,256	31,983,349	31,232,556	3.16%	986,949	18,788,553
E312	Boiler Plant Equipment	8,623,422	8,679,337	8,653,709	3.18%	275,188	5,533,214
E314	Turbo Generating Units	3,918,858	3,918,858	3,918,858	3.31%	129,714	2,382,313
E315	Accessory Electric Equip.	2,377,984	2,420,179	2,400,840	3.07%	73,706	1,334,875
E316	Misc. Power Plant Equip.	6,235,545	6,561,728	6,412,227	3.82%	244,947	3,136,065
	TOTAL	<u>51,501,064</u>	<u>53,563,451</u>	<u>52,618,190</u>	<u>3.25%</u>	<u>1,710,504</u>	<u>31,175,020</u>
COLSTRIP 3							
E311	Structures & Improvements	28,829,642	28,882,948	28,858,516	2.45%	707,034	14,566,340
E312	Boiler Plant Equipment	113,898,277	115,756,485	113,618,072	2.68%	3,044,964	57,262,237
E314	Turbo Generating Units	32,936,825	33,180,681	33,068,914	2.97%	982,147	14,166,239
E315	Accessory Electric Equip.	6,401,615	6,401,615	6,401,615	2.47%	158,120	2,874,151
E316	Misc. Power Plant Equip.	454,762	480,140	468,508	2.86%	13,399	210,034
	TOTAL	<u>182,521,121</u>	<u>184,701,869</u>	<u>182,415,625</u>	<u>2.69%</u>	<u>4,905,664</u>	<u>89,079,001</u>
COLSTRIP 4							
E311	Structures & Improvements	26,542,394	26,595,701	26,571,269	2.54%	674,910	11,552,369
E312	Boiler Plant Equipment	99,709,843	100,508,440	100,142,416	2.75%	2,753,916	43,898,286
E314	Turbo Generating Units	27,895,777	28,602,598	28,278,638	2.94%	831,392	10,813,318
E315	Accessory Electric Equip.	5,589,362	5,596,707	5,593,341	2.52%	140,952	2,163,849
E316	Misc. Power Plant Equip.	650,784	676,163	664,531	2.79%	18,540	277,867
	TOTAL	<u>160,388,160</u>	<u>161,979,609</u>	<u>161,250,195</u>	<u>2.74%</u>	<u>4,419,710</u>	<u>68,705,690</u>
COLSTRIP 3 & 4 COMMON							
E311	Structures & Improvements	71,951,771	72,034,845	71,996,769	2.33%	1,677,525	35,209,226
E312	Boiler Plant Equipment	20,855,440	20,915,298	20,887,863	2.48%	518,019	10,585,040
E314	Turbo Generating Units	274,553	274,553	274,553	2.62%	7,193	125,852
E315	Accessory Electric Equip.	7,706,935	7,748,971	7,729,705	2.31%	178,556	3,422,068
E316	Misc. Power Plant Equip.	4,861,282	5,098,460	4,989,753	2.79%	139,214	2,083,870
	TOTAL	<u>105,649,981</u>	<u>106,072,127</u>	<u>105,878,643</u>	<u>2.38%</u>	<u>2,520,507</u>	<u>51,426,057</u>
COLSTRIP 1-4 COMMON							
E316	Misc. Power Plant Equip.	253,865	253,865	253,865	2.46%	6,245	123,888
	TOTAL	<u>253,865</u>	<u>253,865</u>	<u>253,865</u>	<u>2.46%</u>	<u>6,245</u>	<u>123,888</u>
	COLSTRIP COMMON FERC ADJ.	8,316,981		8,316,981			
	COLSTRIP DEF DEPR FERC ADJ.	2,449,668		2,449,668			
	Total Plant and Acc. Deprec.	<u>647,044,432</u>		<u>650,197,157</u>		<u>17,794,640</u>	<u>329,162,409</u>

AMA Adj. (8,898,250)
AMA Acum Depr 320,264,159

Settlement Stipulation, as revised
by the 15th Supplemental Order in
WUTC Docket No. UE-011570

Exhibit A
Exhibit A-3 (Revised)
Exhibit A to Petition of Puget
Sound Energy, Inc.
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			Amount before
			Prod. Adj.
70	Support for Revenue Requirement - Expenses		
71			
72	Order	Description	
73	50004011	1&2 Sup & Eng	76,685
74	50005011	3&4 Sup & Eng	108,581
75	50204001	1&2 Steam Exp	1,217,034
76	50205001	3&4 Steam Exp	624,831
77	50504001	1&2 Elec Exp	(208,933)
78	50505001	3&4 Elec Exp	(223,913)
79	50604001	1&2 Misc Exp	3,320,269
80	50605001	3&4 Misc Exp	2,515,968
81	50605002	3&4 Steam	(2,399)
82	50704001	1&2 Rents	95,991
83	50705001	3&4 Rents	131,692
84	51004001	1&2 Maint Supv	669,151
85	51005001	3&4 Maint Supv	539,405
86	51104001	1&2 Maint of Struct	405,072
87	51105001	3&4 Maint of Struct	373,938
88	51204001	1&2 Maint of Boiler	4,902,128
89	51205001	3&4 Maint of Boiler	5,967,278
90	51304001	1&2 Maint of E Plant	(178,069)
91	51305001	3&4 Maint of E Plant	705,533
92	51404001	1&2 Maint of Misc	4,578,888
93	51405001	3&4 Maint of Misc	1,159,196
94		Property Taxes-Montana	6,027,509
95		Electric Energy Tax	1,729,406
96	403xxxx	Depreciation	17,794,640
97			<u>\$52,329,884</u>

Exhibit A-4 Production Adjustment UE-011570

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**PUGET SOUND ENERGY-ELECTRIC
PRODUCTION ADJUSTMENT
FOR THE TWELVE MONTHS ENDED JUNE 30, 2001
GENERAL RATE INCREASE**

LINE NO.	DESCRIPTION	PRO FORMA PRODUCTION AMOUNT	2.84%	FIT 35%
1	PRODUCTION WAGE INCREASE			
2	PURCHASED POWER	0	0	0
3	OTHER POWER SUPPLY	0	0	0
4	TOTAL PRODUCTION WAGE INCREASE	0	0	0
5				
6	PAYROLL OVERHEADS	783,939	(22,264)	7,792
7	PROPERTY INSURANCE	1,026,555	(29,154)	10,204
8	TOTAL A&G	1,810,494	(51,418)	17,996
9				
10	DEPRECIATION PRODUCTION PROPERTY			
11	DEPRECIATION / AMORTIZATION	37,325,792	(1,060,052)	263,024
12	PURCHASED POWER	3,526,620	(100,156)	35,055
13	FUEL	0	0	0
14	TOTAL	40,852,412	(1,160,209)	298,079
15				
16	TAXES OTHER-PRODUCTION PROPERTY			
17	PROPERTY TAXES - WASHINGTON	3,041,963	(86,392)	30,237
18	PROPERTY TAXES - MONTANA	6,027,509	(171,181)	59,913
19	ELECTRIC ENERGY TAX	1,729,406	(49,115)	17,190
20	PAYROLL TAXES	630,032	(17,893)	6,263
21	TOTAL TAXES OTHER	11,428,910	(324,581)	113,603
22				
23	INCREASE(DECREASE) INCOME		1,536,208	
24	INCREASE(DECREASE) FIT			429,678
25	INCREASE(DECREASE) NOI			1,106,530
26				
27	RATE BASE:			
28	PRODUCTION PROPERTY	1,065,115,283		
29	COLSTRIP COMMON FERC ADJ.	8,316,981		
30	COLSTRIP DEF DEPR FERC ADJ.	2,449,668		
31	ENCOGEN ACQUISITION ADJ.	60,574,557		
32	BPA POWER EXCHANGE INVESTMENT	51,135,941	sum of L32 thru	293,050,941
33	TENASKA REGULATORY ASSET	229,424,000	L34	284,728,294
34	CABOT OIL REGULATORY ASSET	12,491,000		
35	LESS ACCUM. DEPRECIATION	(519,770,787)		
36	LESS ACCUM. AMORTIZATION	(3,186,245)		
37	NET PRODUCTION PROPERTY	906,550,398		
38				
39	DEDUCT:			
40	LIBR. DEPREC. PRE 1981 (EOP)	(5,250,238)		
41	LIBR. DEPREC. POST 1980 (EOP)	(94,132,216)		
42	OTHER DEF. TAXES (EOP)	(17,930,541)		
43	ADJUSTMENT TO RATE BASE	789,237,403	(22,414,342)	766,823,061
	Plus Snoqualmie CWIP			482,094,767
				11,682,398
				493,777,165

Exhibit A-5 Power Costs UE-011570

**PUGET SOUND ENERGY-ELECTRIC
POWER COSTS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2001
GENERAL RATE INCREASE**

LINE NO. DESCRIPTION	ACTUAL	PROFORMA	INCREASE (DECREASE)
1 PRODUCTION EXPENSES:			
2 FUEL	\$ 297,843,394	\$ 93,684,510	\$ (204,158,884)
3 PURCHASED AND INTERCHANGED	2,226,570,459	534,528,072	(1,692,042,387)
4 WHEELING	31,116,222	41,435,360	10,319,138
5 OTHER POWER SUPPLY EXPENSES	46,736,543	51,597,585	4,861,042
6 TRANS. EXP. INCL. 500KV O&M	352,506	342,495	(10,011)
7 SALES FOR RESALE	(1,766,314,721)	(37,525,193)	1,728,789,528
8 PURCHASES/SALES OF NON-CORE GAS	(22,281,093)	1,077,379	23,358,472
9 WHEELING FOR OTHERS	(7,762,159)	(10,902,262)	(3,140,103)
10 SUBTOTAL	\$ 806,261,151	\$ 674,237,946	\$ (132,023,205)
11			
12 LESS: SALES FOR RESALE	1,766,314,721	37,525,193	(1,728,789,528)
13 LESS: WHEELING FOR OTHERS	7,762,159	10,902,262	3,140,103
14 SCH. 94 - RES./FARM CREDIT	(46,773,115)	-	46,773,115
15 TOTAL	\$ 2,533,564,916	\$ 722,665,401	\$ (1,810,899,515)
16 TRANS. EXP. INCL. 500KV O&M	(352,506)		
17 PURCHASES/SALES OF NON-CORE GAS	22,281,093		
18 POWER COSTS PER G/L	\$ 2,555,493,503		
19 INCREASE(DECREASE) INCOME			\$ 1,810,899,515
20			
21 INCREASE(DECREASE) FIT @	35%		633,814,830
22 INCREASE(DECREASE) NOI			\$ 1,177,084,685

Exhibit B: Power Costs Subject to PCA Sharing

Row	Example	Jul 02 - Jun 03	Explanation or source
5	Return on Fixed RB	\$ 71,035,988	from Exhibit A-1 lines 11&12 - production and transmission ratebase adjusted to Rate Year
6	Other Fixed Costs	120,513,555	from Exhibit A-1 lines 15,19,22-26 (557, Hydro and Other Prod. O&M, 500 KV O&M,
7	Subtotal Fixed Costs	\$ 191,549,544	Depreciation fixed, Property tax) adjusted to Rate Year
8	Total Variable Component Actual		
9	Steam Oper. Fuel	501	SAP - actual
10	Other Pwr Gen Fuel	547	SAP - actual
11	Other Elec Revenues	45600012, 18	SAP - actual Non Core Gas (sales) / purchases orders 45600012, 45600018
12	Purchase Power	555	SAP - actual
13	Sales to Other Util	447	SAP - actual
14	Wheeling	565	SAP - actual
15	Transmission Revenue	45600017	SAP - actual Transmission revenues on 3rd AC, Northern Inter tie, Colstrip lines
16	Regulatory Assets	32,911,879	from Exhibit D line 35; Return on regulatory assets for PCA period
17			
18	SUBTOTAL before Adjustments	642,456.32	\$ 854,272,871
19			
20	Adjustments:		
21	Prudence from UE-921262		Prudence adj. = 3% * March Pt 2 payments; and 1.2% * Tanaska payments
22	Contract price adjustment	(2,260,152)	from Exhibit E line 42
23	Colstrip availability adjustment	(1,094,429)	from Exhibit F line 40
24	New resource pricing adjustment	(531,478)	from Exhibit G line 38
25			
26	Subtotal Adjustments	(3,886,059)	
27			
28	Total allowable cost	\$ (9,555,559)	
29			
30	PCA period delivered load	\$ 844,717,312	
31	Baseline Power Cost	\$ 19,110,518	Actual delivered MWh during PCA period = Total load net of losses
32		\$ 639,964,611	Base line rate from Exhibit A-1 line 25
33	Imbalance for Sharing	\$ 4,752,701	to Exhibit C column (C). A portion of the imbalance will be allocated to firm wholesale
34	positive is potential customer surcharge, negative is potential customer credit		customers based upon the allocation used in the most recent Docket approving rate spread.
35			
36	Company's Share		
37	First band - deadband	\$ 20,000,000	band limit +/-
38	2nd Band - next	\$ 20,000,000	100%
39	3rd Band - next	\$ 80,000,000	50%
40	4th Band greater than	\$120,000,000	10%
41	Subtotal Company Share before Cap	4,752,701	5%
42			
43	Customer Share (deferral account)	\$ -	to Exhibit C column (G)
			to Exhibit C column (D)

Exhibit C - Application of \$40 million Cap

Overall Cap For Four Year Period: As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed in the settlement terms for the PCA. If this cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to Customer and 1% of costs and benefits to Company. The cap is removed at end of the fourth year, and any remaining deferred balances associated with the cap are set for refund or collection at that time.

Example: 1 First year per draft Exhibit examples; next 3 years high power costs

Row	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Imbalance for Sharing Ex. B line 33	Customer Annual Share = "Deferral" Ex. B line 43	Customer Annual Share over Cap at 99%	End Period Customer Deferral Balance	Company Annual Share Ex. B line 41	Potential transfer (to) / from customer	Company share over Cap at 1%	End Period Company Share	Company Accum Share w/o Cap	Accum. Amount Over Cap	Annual Change In Amount over Cap
16	PCA Yr #1 \$ (5.83)	\$ -	\$ -	\$ -	\$ (5.83)	\$ -	\$ -	\$ (5.83)	\$ (5.83)	\$ -	\$ -
17	PCA Yr #2 \$ 30.00	\$ 5.00	\$ -	\$ 5.00	\$ 25.00	\$ -	\$ -	\$ 19.17	\$ 19.17	\$ -	\$ -
18	PCA Yr #3 \$ 30.00	\$ 5.00	\$ 4.13	\$ 14.13	\$ 25.00	\$ (4.17)	\$ 0.04	\$ 40.04	\$ 44.17	\$ 4.17	\$ 4.17
19	PCA Yr #4 \$ 30.00	\$ 5.00	\$ 24.75	\$ 43.88	\$ 25.00	\$ (25.00)	\$ 0.25	\$ 40.29	\$ 69.17	\$ 29.17	\$ 25.00
21	Check \$ 84.2			\$ 43.9				\$ 40.3			
22											

Exhibit C - Application of \$40 million Cap

Overall Cap For Four Year Period: As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed in the settlement terms for the PCA. If this cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to Customer and 1% of costs and benefits to Company. The cap is removed at end of the fourth year, and any remaining deferred balances associated with the cap are set for refund or collection at that time.

Example: 2 Four year cost scenario discussed at May 23rd PCA Collaborative

Row	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		Customer Annual Share = "Deferral" Ex. B line 43	Customer Annual Share over Cap at 99%	End Period Customer Deferral Balance	Company Annual Share Ex. B line 41	Potential transfer (to) / from customer	Company share over Cap at 1%	End Period Company Share	Company Accum w/o Cap	Accum. Amount Over/Cap	Annual Change in Amount over Cap
26	PCA Yr #1	\$ 5.0	\$ -	\$ 5.0	\$ 25.0	\$ -	\$ -	\$ 25.0	\$ 25.0	\$ -	\$ -
27	PCA Yr #2	\$ -	\$ -	\$ 5.0	\$ -	\$ -	\$ -	\$ 25.0	\$ 25.0	\$ -	\$ -
28	PCA Yr #3	\$ (100.0)	\$ -	\$ (99.0)	\$ (36.0)	\$ -	\$ -	\$ (11.0)	\$ (11.0)	\$ -	\$ -
29	PCA Yr #4	\$ 36.0	\$ -	\$ (51.0)	\$ 28.0	\$ -	\$ -	\$ 17.0	\$ 17.0	\$ -	\$ -
30	Check	\$ (34.0)	\$ -	\$ (51.0)	\$ -	\$ -	\$ -	\$ 17.0	\$ 17.0	\$ -	\$ -
31											
32											
33											
34											
35											

Exhibit C - Application of \$40 million Cap

Overall Cap For Four Year Period: As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed in the settlement terms for the PCA. If this cap is exceeded, sharing thereafter is adjusted to 89% of costs and benefits to Customer and 1% of costs and benefits to Company. The cap is removed at end of the fourth year, and any remaining deferred balances associated with the cap are set for refund or collection at that time.

Example: 3 Three high power cost years followed by very low power cost year.

Row	\$ In Millions											
	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
	Imbalance for Sharing Ex. B line 33	Customer Annual Share = "Deferral" Ex. B line 43	Customer Annual Share over Cap at 99%	End Period Customer Deferral Balance	Company Annual Share Ex. B line 41	Potential transfer (to) / from customer	Company share over Cap at 1%	End Period Company Share	Company Accum w/o Cap	Accum. Amount Over Cap	Annual Change in Amount over Cap	
39	PCA Yr #1	\$ 5.0	\$ -	\$ 5.0	\$ 25.0	\$ -	\$ -	\$ 25.0	\$ 25.0	\$ -	\$ -	
40	PCA Yr #2	\$ 100.0	\$ 64.0	\$ 20.8	\$ 88.8	\$ (21.0)	\$ 0.2	\$ 40.2	\$ 61.0	\$ 21.0	\$ 21.0	
41	PCA Yr #3	\$ 36.0	\$ 8.0	\$ 27.7	\$ 125.5	\$ (28.0)	\$ 0.3	\$ 40.5	\$ 89.0	\$ 49.0	\$ 28.0	
42	PCA Yr #4	\$ (100.0)	\$ (64.0)	\$ (35.6)	\$ 25.9	\$ (36.0)	\$ (0.4)	\$ 40.1	\$ 53.0	\$ 13.0	\$ (36.0)	
43	Check	\$ 66.0	\$ -	\$ 25.9	\$ -	\$ -	\$ -	\$ 40.1	\$ -	\$ -	\$ -	
44								\$ 40.1				

Exhibit C - Application of \$40 million Cap

Overall Cap For Four Year Period: As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed in the settlement terms for the PCA. If this cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to Customer and 1% of costs and benefits to Company. The cap is removed at end of the fourth year, and any remaining deferred balances associated with the cap are set for refund or collection at that time.

Example: 4 Similar to example 3, but fortunes are reversed with 3 low cost years followed by a high cost year.
\$ in Millions

Row	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Imbalance for Sharing Ex. B line 33	Customer Annual Share = "Deferral" Ex. B line 43	Customer Annual Share over Cap at 99%	End Period Customer Deferral Balance	Company Annual Share Ex. B line 41	Potential transfer (to) / from customer	Company share over Cap at 1%	End Period Company Share	Company Accum w/o Cap	Accum. Amount Over Cap	Annual Change in Amount over Cap
52	PCA Yr #1 \$	(5.0) \$	- \$	(5.0) \$	(25.0) \$	- \$	- \$	(25.0) \$	(25.0) \$	- \$	- \$
53	PCA Yr #2 \$	(100.0) \$	(20.8) \$	(89.8) \$	(36.0) \$	21.0 \$	(0.2) \$	(40.2) \$	(61.0) \$	(21.0) \$	(21.0) \$
54	PCA Yr #3 \$	(36.0) \$	(8.0) \$	(125.5) \$	(28.0) \$	28.0 \$	(0.3) \$	(40.5) \$	(89.0) \$	(49.0) \$	(28.0) \$
55	PCA Yr #4 \$	100.0 \$	35.6 \$	(25.9) \$	36.0 \$	(36.0) \$	0.4 \$	(40.1) \$	(53.0) \$	(13.0) \$	36.0 \$
56	Check \$	(86.0) OK		(25.9) \$				(40.1) \$			
57								\$ (40.1)			

Exhibit D: Regulatory Assets

Row		Interest	Amort	Balance	PCA (Jul-Jun) Amortization	PCA (Jul-Jun) Ratebase (AMA)	Return 7.30%	35% Pre Tax Return
4	Cabot Buyout							
5		709,000	(312,000)	12,985,000				
6	2000 \$ 12,588,000	720,000	(741,000)	12,964,000				
7	2001 \$ -	731,000	(1,070,000)	12,625,000	(1,070,000)	12,491,033	\$ 911,845	\$ 1,402,839
8	2002 \$ -	-	(1,409,000)	11,216,000	(1,588,500)	11,170,908	\$ 815,476	\$ 1,254,579
9	2003 \$ -	-	(1,768,000)	9,448,000	(1,965,500)	9,398,408	\$ 686,084	\$ 1,055,514
10	2004 \$ -	-	(2,163,000)	7,285,000	(2,388,500)	7,228,408	\$ 527,674	\$ 811,806
11	2005 \$ -	-	(2,614,000)	4,671,000				
12	2006 \$ -	-						
13								
14	Tenaska							
15	1998 \$ 215,000,000	8,754,000	(1,952,000)	221,802,000				
16	1999 \$ -	8,795,000	(3,863,000)	226,734,000				
17	2000 \$ -	8,849,000	(5,463,000)	230,120,000				
18	2001 \$ -	8,838,000	(7,382,000)	231,576,000				
19	2002 \$ -	8,749,000	(9,494,000)	230,831,000	(9,494,000)	229,424,000	\$ 16,747,952	\$ 25,766,080
20	2003 \$ -	-	(11,924,000)	218,907,000	(13,334,000)	218,552,512	\$ 15,954,333	\$ 24,545,128
21	2004 \$ -	-	(14,744,000)	204,163,000	(16,326,000)	203,765,512	\$ 14,874,882	\$ 22,884,434
22	2005 \$ -	-	(17,908,000)	186,255,000	(19,261,500)	185,914,637	\$ 13,571,769	\$ 20,879,644
23	2006 \$ -	-	(20,615,000)	165,640,000				
24								
25	BEP							
26	2001			54,662,518				
27	2002	(3,526,620)	(3,526,620)	51,135,898	(3,526,620)	51,135,941	\$ 3,732,924	\$ 5,742,960
28	2003	(3,526,620)	(3,526,620)	47,609,278	(3,526,620)	47,609,278	\$ 3,475,477	\$ 5,346,888
29	2004	(3,526,620)	(3,526,620)	44,082,658	(3,526,620)	44,082,658	\$ 3,218,034	\$ 4,950,822
30	2005	(3,526,620)	(3,526,620)	40,556,038	(3,526,620)	40,556,038	\$ 2,960,591	\$ 4,554,755
31	2006	(3,526,620)	(3,526,620)	37,029,418				
32								
33								
34								
35								
36								
37								
38								
39								

From	To	Amortization	AMA Ratebase	Return	Return Pre-tax
Jul-02	Jun-03	\$ (14,090,620)	\$ 293,050,974	\$ 21,392,721	\$ 32,911,879
Jul-03	Jun-04	\$ (18,449,120)	\$ 277,332,698	\$ 20,245,287	\$ 31,146,595
Jul-04	Jun-05	\$ (21,818,120)	\$ 257,246,578	\$ 18,779,000	\$ 28,890,770
Jul-05	Jun-06	\$ (25,176,620)	\$ 233,699,083	\$ 17,060,033	\$ 26,246,205

PCA/C
Exhibit C - Contract Adjustments

Row	Note	Limit - Rate or Total Cost per UE-011570	PCA Period			Adjust for Positive Differences
			Generation MWh	NUG Gen. MWh	NUG Dispi. MWh	
7	CONTRACTS					
8	Baker Replacement					
9	BC Hydro Point Roberts					
10	BPA WNP-3 Exchange Power	\$ 67.00	21,432			\$ 1,436,000 \$ 67.00
11	BPA WNP-3 Return	\$ 26.17	384,834			\$ 10,082,000 \$ 26.30
12	BPA Snohomish Conservation					\$ 4,733,000 \$ 51.35
13	CSPE	\$ 51.35	92,170			\$ (0.00) \$
14	Mid-Columbia					
15	Canadian Entitlement and CEA-EA					
16	MPC Firm Contract-Demand	\$ 29,392,000				\$ 29,732,000
17	MPC Firm Contract-Energy					
18	PPL Contract 15 yr					
19	Supplemental Entitlement Cap					
20	North Wasco	\$ 62.85	39,031			\$ 2,500,000 \$ 64.05
21	WWVP Contract 15 Yr					
22	PG&E Exchange Storage Acctg					
23	OF Shippo Hutch Creek					
24	OF Koma Kushan Hydro	\$ 30.04	1,731			\$ 52,000 \$ 30.04
25	OF March Point Cogen 1 Winter	\$ 74.87	32,892			\$ 2,448,000 \$ 74.86
26	OF March Point Cogen 1 Summer	\$ 61.01	436,000	436,000		\$ 26,639,600 \$ 61.10
27	OF March Point Cogen 2 Winter	\$ 43.70	281,000	181,000	100,000	\$ 12,279,700 \$ 43.70
28	OF March Point Cogen 2 Summer	\$ 66.00	330,000	330,000		\$ 22,011,000 \$ 66.70
29	OF Port Townsend Hydro	\$ 55.30	232,000	132,000	100,000	\$ 12,829,600 \$ 55.30
30	OF PERC Playallup	\$ 26.21	2,694			\$ 78,000 \$ 26.21
31	OF Spokane MSW		141,552			\$ 12,397,000 \$ 87.58
32	OF Sumas Winter	\$ 61.84	663,000	663,000		\$ 54,631,200 \$ 82.40
33	OF Sumas Summer	\$ 59.20	461,000	381,000	100,000	\$ 27,291,200 \$ 59.20
34	OF Sylvania	\$ 51.37	1,421			\$ 73,000 \$ 51.37
35	OF Tenasta (excl. Reg. Amort.)	\$ 31.84	1,958,028	1,859,028	100,000	\$ 62,089,488 \$ 31.70
36	OF Twin Falls	\$ 75.00	89,955			\$ 5,246,625 \$ 75.00
37	OF Weeks Falls	\$ 75.00	12,542			\$ 940,650 \$ 75.00
38	Stookumehuck					
39	TOTAL					\$ 1,094,429
40						\$ (1,094,429)

Reverse sign and enter on Exhibit B line 22 \$ (1,094,429)

- 42 Notes:
- 43 Exchange: No Adjustment. Either power for power exchange at zero cost or flood control for power at zero cost.
- 44 N/A: No Adjustment. Zero cost contracts.
- 45 Rate Limit: Calculate actual rate for PCA period, compare with contract rate assumed in revenue requirements; multiply rate change (if positive) times contract generation.
- 46 Actual Cost: No Adjustment. Either no rate specified in contract, or rate based upon DJ market index, or as agreed.
- 47 Total Cost: Limit based upon total cost in rate year because contract escalation is in fixed demand charges.
- 48 NUG Rate Limit: Calculate actual rate monthly assuming actual availability with no displacement; compare with average seasonal rate-year contract rate (also without displacement); multiply rate change (if positive) times total of actual contract generation + displacement.

CONFIDENTIAL
Exhibit F - Colstrip Availability Adjustment

Row

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

5		<u>182</u>	<u>384</u>		
6		307	370	PSE Wtd	days
7	PSE MW ->				
8	Jul-02	85.00%	85.00%	85.0%	31
9	Aug-02	85.00%	85.00%	85.0%	31
10	Sep-02	85.00%	85.00%	85.0%	30
11	Oct-02	85.00%	85.00%	85.0%	31
12	Nov-02	85.00%	85.00%	85.0%	30
13	Dec-02	85.00%	85.00%	85.0%	31
14	Jan-03	85.00%	85.00%	85.0%	31
15	Feb-03	85.00%	85.00%	85.0%	28
16	Mar-03	85.00%	0.00%	38.5%	31
17	Apr-03	85.00%	0.00%	38.5%	30
18	May-03	85.00%	0.00%	38.5%	31
19	Jun-03	85.00%	0.00%	38.5%	30

20

21 12 mo Average 85.00% 56.59% **69.47%**

22 Weighted by days in the month Weighted by Plant Capacity and days/month

23

24

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

26 Less than 70% yes yes, penalty assessed

27 Actual Ratio 69.47%

28 Target Ratio 75.00% per Collaborative agreement

29 Penalty -5.53%

30

31

32 Penalty Ratio = **-7.37%** = penalty $\frac{-5.53\%}{75.00\%}$ per Collaborative agreement

33

34

35

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

37

38 Total Fixed Cost \$ 78,868,054 from Exhibit A-3 (Colstrip Total Revenue Requirement)

39

40 Penalty Ratio = -7.37%

41 Penalty \$ **(5,812,478)** to Exhibit B line 23

Exhibit F - Data Input Page

Availability data from Colstrip Operation Reports

ROW		1&2	3&4	days	
5	Jan-01	98.66%	88.73%	31	Actual data
6	Feb-01	86.24%	97.78%	28	
7	Mar-01	95.36%	72.76%	31	
8	Apr-01	91.56%	48.20%	30	
9	May-01	75.12%	69.74%	31	
10	Jun-01	52.30%	71.73%	30	
11	Jul-01	94.38%	93.44%	31	
12	Aug-01	91.42%	97.77%	31	
13	Sep-01	80.02%	93.18%	30	
14	Oct-01	96.70%	95.99%	31	
15	Nov-01	96.71%	90.40%	30	
16	Dec-01	90.64%	86.21%	31	
17	Jan-02	93.60%	47.87%	31	
18	Feb-02	91.01%	79.26%	28	
19	Mar-02	97.14%	88.04%	31	
20	Apr-02	94.44%	93.99%	30	
21	May-02	85.00%	85.00%	31	
22	Jun-02	85.00%	85.00%	30	
23	Jul-02	85.00%	85.00%	31	
24	Aug-02	85.00%	85.00%	31	
25	Sep-02	85.00%	85.00%	30	
26	Oct-02	85.00%	85.00%	31	
27	Nov-02	85.00%	85.00%	30	
28	Dec-02	85.00%	85.00%	31	
29	Jan-03	85.00%	85.00%	31	
30	Feb-03	85.00%	85.00%	28	
31	Mar-03	85.00%	0.00%	31	
32	Apr-03	85.00%	0.00%	30	
33	May-03	85.00%	0.00%	31	
34	Jun-03	85.00%	0.00%	30	
35	Jul-03			31	
36	Aug-03			31	
37	Sep-03			30	
38	Oct-03			31	
39	Nov-03			30	
40	Dec-03			31	
41	Jan-04			31	
42	Feb-04			29	
43	Mar-04			31	
44	Apr-04			30	
45	May-04			31	
46	Jun-04			30	
<hr/>					
59	Jul-05			31	
60	Aug-05			31	
61	Sep-05			30	
62	Oct-05			31	
63	Nov-05			30	
64	Dec-05			31	
65	Jan-06			31	
66	Feb-06			28	
67	Mar-06			31	
68	Apr-06			30	
69	May-06			31	
70	Jun-06			30	

Actual data

Example data

Exhibit G - New Resource Adjustment

Row

3 **For New Resources with a Terms Longer than 2 Years**

4

5

Name Sample new plant

6

Description Combined cycle gas turbine

7

In-service date January 2003

8

9

10

PCA Period July 2002 - June 2003

11

13 **Total Variable Component Actual**

14	Steam Oper. Fuel	501	\$	-
15	Other Pwr Gen Fuel	547		33,000,000
16	Other Elec Revenues	45600012, 18		-
17	Purchase Power	555		-
18	Sales to Other Util	447		-
19	Wheeling	565		750,000
20	Transmission Revenue	45600017		-
21			\$	33,750,000

22

23

PCA Period Generation (MWh) 750,000

24

25

Actual Variable Cost (\$/MWh) \$45.000

26

27

28

Baseline Power Cost Rate (\$/MWh) \$44.482

29

30

Lesser of Actual Cost or Baseline Rate	
Baseline Power Cost Rate	\$44.482

31

32

33

Adjustment Needed? Yes

34

Adjustment needed if Baseline rate is lower than actual variable cost

35

36

Adjustment Rate (\$/MWh) -\$0.518

37

Adjustment volume (MWh) 750,000

38

Adjustment Amount (\$) **\$ (388,500)** to Exhibit B line 24