Power Cost Adjustment Mechanism
Annual Report

Twelve Months Ended June 30, 2003

Puget Sound Energy
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Twelve Months Ended June 30, 2003

Index

Puget Sound Energy
Power Cost Adjustment Mechanism
Annual Report
Twelve Months Ended June 30, 2003

PCA Settlement Stipulation - Exhibit A-1 Power Cost Rate

Row		Test Year 12 Mo End 6/30/01				Rate Year
13	Regulatory Assets (Variable)	$ 284,728,294				
14	Transmission Rate Base (Fixed)	124,643,364				
15	Production Rate Base (Fixed)	493,777,165				
16		$ 903,148,823				
17	Net of tax rate of return	7.30%	**Test Year**			
18			**12 Mo End 6/30/01**			
19			**$/MWh**			
20	Regulatory Asset Recovery	$ 31,977,178	$ 1.677		(c)	
21	Fixed Asset Recovery-Prod Factored	54,142,951	$ 2.840	(a)		55,725,557
22	Fixed Asset Recovery Other	15,310,432	$ 0.803	(a)		15,310,432
23	501-Steam Fuel	32,511,186	$ 1.705		(c)	
24	555-Purchased power	526,980,333	$ 27.643		(c)	
25	557-Other Power Exp	11,499,089	$ 0.603	(a)		11,835,209
26	547-Fuel	61,173,325	$ 3.209		(c)	
27	565-Wheeling	41,435,360	$ 2.174		(c)	
28	Variable Transmission Income	(6,510,985)	$ (0.342)		(c)	
29	Hydro and Other Pwr.	51,597,583	$ 2.707	(a)		53,105,787
30	447-Sales to Others	(37,525,193)	$ (1.968)		(c)	
31	456-Subaccounts 00012 & 00018 and 00035 & 00036	1,077,379	$ 0.057		(c)	
32	Transmission Exp - 500KV	342,495	$ 0.018	(a)		342,495
33	Depreciation-Production	36,265,740	$ 1.902	(a)		37,325,792
34	Depreciation-Transmission	4,851,654	$ 0.254	(a)		4,851,654
35	Property Taxes-Production	8,343,174	$ 0.438	(a)		8,600,747
36	Property Taxes-Transmission	4,441,860	$ 0.233	(a)		4,441,860
37	Subtotal & Baseline Rate	$ 837,913,560	**$ 43.953**	(b)		191,539,533
38	Revenue Sensitive Items	0.9552337				
39		$ 877,181,741				8,343,174
40	Test Year Load (MWH's)	19,063,867	<-- includes Firm Wholesale			
41		Before Rev. Sensitive Items	After Rev. Sensitive Items			
42	Power Cost in Rates with Revenue Sensitive Items (the adjusted baseline		46.013			
43	sum of (a) = Fixed Rate Component	9.798	10.257			
44	(b) = Power Cost Rate	43.953	46.013			
45	sum of (c) = Variable Power Rate	34.155	35.756			
46	Component					
47						
48	* Regulatory Assets are Tenaska, Encogen Fuel Buyout and BEP					

Puget Sound Energy
Power Cost Adjustment Mechanism
Annual Report
Twelve Months Ended June 30, 2003

PCA Settlement Stipulation - Exhibit A-1 Power Cost Rate Updated

Row			PCA Period 12 Mo End 6/30/03		
13	Regulatory Assets (Variable)	$	293,050,974		
14	Transmission Rate Base (Fixed)		124,643,364		
15	Production Rate Base (Fixed)		493,777,165		
16		$	911,471,503		
17	Net of tax rate of return		7.30%		
18				PCA Periodd 12 Mo End 6/3	
20				$/MWh	
21	Regulatory Asset Recovery	$	32,911,879	$ 1.716	(c)
22	Fixed Asset Recovery-Prod Factored		55,725,557	$ 2.905	(a)
23	Fixed Asset Recovery Other		15,310,432	$ 0.798	(a)
24	501-Steam Fuel		31,562,320	$ 1.645	(c)
25	555-Purchased power		724,568,741	$ 37.772	(c)
26	557-Other Power Exp		11,835,209	$ 0.617	(a)
27	547-Fuel		28,191,542	$ 1.470	(c)
28	565-Wheeling		39,906,926	$ 2.080	(c)
29	Variable Transmission Income		(6,997,053)	$ (0.365)	(c)
30	Hydro and Other Pwr.		53,105,787	$ 2.768	(a)
31	447-Sales to Others		(166,771,845)	$ (8.694)	(c)
32	456-Subaccounts 00012 & 00018 and 00035 & 00036		(3,624,989)	$ (0.189)	(c)
33	Transmission Exp - 500KV		352,506	$ 0.018	(a)
34	Depreciation-Production		37,325,792	$ 1.946	(a)
35	Depreciation-Transmission		4,851,654	$ 0.253	(a)
36	Property Taxes-Production		8,600,747	$ 0.448	(a)
37	Property Taxes-Transmission		4,441,860	$ 0.232	(a)
38	Subtotal & Baseline Rate	$	871,297,066	**$ 45.420**	(b)
39	Revenue Sensitive Items		0.9552337		
40		$	912,129,739		
41	Rate Year Load		19,182,454	<-- includes Firm Whc	
42			Before Rev. Sensitive Items	After Rev. Sensitive Ite	
43	Power Cost in Rates with Revenue Sensitive Items (the adjusted baseline			47.549	
44	sum of (a) = Fixed Rate Component		9.985	10.453	
45	(b) = Power Cost Rate		45.420	47.549	
46	sum of (c) = Variable Power Rate Component		35.435	37.096	
47					
48					
49	* Regulatory Assets are Tenaska, Encogen Fuel Buyout and BEP				

PCA Settlement Stipulation - **Exhibit B- PCA Mechanism Calculation**					
			PCA Period		
Row			**7/1/02-6/30/03**		**Explanation or source**
13					
14	Return on Fixed RB		$ 55,725,557		from Schedule A-1 NEW line 11 - Fixed Asset Recovery adjust to monthly basis.
15	Other Fixed Costs		$ 135,823,988		from Schedule A-1 NEW lines 12,15,19,22,23,24,25 & 26 **(1)**
16	Subtotal Fixed Costs		$ 191,549,544		from Schedule A-1 NEW line 27 - Subtotal adjusted to monthly basis.
17	Total Variable Component Actual	FERC Acct.			
18	Steam Oper. Fuel	501	$ 1,562,320		SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
19	Other Pwr Gen Fuel	547	$ 28,191,542		SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
20	Other Elec Revenues	45600012,18,35,36	$ (3,624,989)		SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
21	Purchase Power	555	$ 727,714,714		SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
22	Sales to Other Util	447	$ (166,771,845)		SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
23	Wheeling	565	$ 39,906,926		SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
24	Transmission Revenue	45600017	$ (6,997,053)		SAP - actual Report GR55 Group Z006, Transmsn rev re: 3rd AC, Northern Intertie, Colstrip
18	Subtotal Variable Components		$ 649,981,616		
19					
27	Regulatory Assets		$ 32,911,879		Workpaper Section 8, Schedule D NEW, line 35 **(2)**
28					
29	SUBTOTAL before Adjustments		$ 874,443,039		

Puget Sound Energy
Power Cost Adjustment Mechanism
Annual Report
Twelve Months Ended June 30, 2003

30	**SUBTOTAL before Adjustments**		$ 874,443,039		
31	**Adjustments:**				
32	Prudence from UE-921262	555	$ (2,134,905)		Workpaper Section 1, Page12, line 19 **(2)**
33	Contract price adjustment	555	$ (661,290)		Workpaper Section 1, Schedule E, line 41 **(2)**
34	Colstrip availability adjustment		-		Workpaper Section 1, Schedule F, line 42 **(2)**
35	New resource pricing adjustment		-		Workpaper Section 1, Schedule G, line 39 **(2)**
36	Firm Wholesale Cost adjustment	555	$ (349,777)		.04% of Subtotal Schedule B, line 22
37	Subtotal Adjustments		$ (3,145,973)		
38					
39	**Total allowable cost (line 28/line 30)**		$ 871,297,066		
40					
41	PCA period delivered load (Kwh)		$ 19,182,454,092		From Subtotal line on Sales of Electricity Report
42	**Baseline Power Cost**	$0.043953	$ 843,126,409		Base line rate from Schedule A-1 NEW line 27
43					
44	Imbalance for Sharing		$ 28,170,657		
45			$ 28,170,657		
46					
47	**Gross PCA**		$ 28,170,657		18230281
48	**Gross PCA Contra**		$ (28,170,657)		18230291
49					
50	**Cumulative Gross PCA**		$ 28,170,657		18230281
51	**Cumulative Gross PCA Contra**		$ (28,170,657)		18230291
52					
53					
54	**Note: This schedule was derived from original PCA collaborative exhibit B**				
	(1) Includes FERC 557, Hydro and Other Pwr., 500 KV O&M, Depreciation fixed, Property tax				
	(2) Worpapers provided under separate letter.				

Puget Sound Energy
Power Cost Adjustment Mechanism
Annual Report
Twelve Months Ended June 30, 2003

Power Cost Adjustment Summary

		Actuals		Baseline		Difference (A)		Company		Customer		Total	
PCA Year		Actuals	Cumulative	Baseline	Cumulative	Monthly Difference	Cumulative Difference	Monthly	Cumulative	Monthly	Cumulative	Monthly Difference	Cumulative Difference
1	Jul.-02	58,023,753	58,023,753	61,616,393	61,616,393	(3,592,640)	(3,592,640)	(3,592,640)	(3,592,640)	-	-	(3,592,640)	(3,592,640)
1	Aug.-02	60,985,232	119,008,984	62,377,208	123,993,601	(1,391,976)	(4,984,617)	(1,391,976)	(4,984,617)	-	-	(1,391,976)	(4,984,617)
1	Sept.-02	66,838,966	185,847,950	60,040,410	184,034,011	6,798,555	1,813,939	6,798,555	1,813,939	-	-	6,798,555	1,813,939
1	Oct.-02	73,011,901	258,859,851	69,523,163	253,557,174	3,488,739	5,302,677	3,488,739	5,302,677	-	-	3,488,739	5,302,677
1	Nov.-02	72,015,099	330,874,951	74,375,539	327,932,713	(2,360,439)	2,942,238	(2,360,439)	2,942,238	-	-	(2,360,439)	2,942,238
1	Dec.-02	86,832,426	417,707,377	84,599,358	412,532,070	2,233,068	5,175,306	2,233,067	5,175,305	-	-	2,233,067	5,175,305
1	Jan.-03	80,419,100	498,126,477	81,723,969	494,256,039	(1,304,869)	3,870,438	(1,304,868)	3,870,438	-	-	(1,304,868)	3,870,438
1	Feb.-03	80,881,452	579,007,928	75,416,275	569,672,315	5,465,176	9,335,614	5,465,176	9,335,614	-	-	5,465,176	9,335,614
1	Mar.-03	84,964,963	663,972,892	77,553,819	647,226,133	7,411,145	16,746,758	7,411,145	16,746,758	-	-	7,411,145	16,746,758
1	Apr.-03	67,860,105	731,832,996	69,473,916	716,700,049	(1,613,811)	15,132,947	(1,613,811)	15,132,947	-	-	(1,613,811)	15,132,947
1	May.-03	63,305,389	795,138,385	65,590,803	782,290,853	(2,285,414)	12,847,533	(2,285,414)	12,847,533	-	-	(2,285,414)	12,847,533
1	Jun.-03	76,158,681	871,297,067	60,835,557	843,126,410	15,323,124	28,170,657	11,237,796	24,085,329	4,085,328	4,085,328	15,323,124	28,170,657

Notes:

(A) A credit balance represents an overrecovery of power costs (baseline rate was greater than actual rate). A debit balance represents an underrecovery of power costs (actual rate was greater than baseline rate).

EXPLANATORY Q & A

What is the purpose of this filing?

In the Commission's Twelfth Supplemental Order in Docket No. UE-011570, the Commission approved the Settlement Stipulation which resolved all electric issues and common electric-natural gas issues in PSE's consolidated rate proceeding, as well as some natural gas issues. The Stipulation defines the agreement reached regarding the establishment of and methodology used, as well as provides for reporting requirements, for the Company's Power Cost Adjustment (PCA) Mechanism. Regarding reporting requirements, the Stipulation requires the Company to file an annual report detailing the power costs included in the PCA deferral calculation. Through its Petition, the Company is requesting approval of the PCA Mechanism activity for the twelve months ended June 30, 2003 including the deferral of under-recovered power costs of $4,085,328. The amount deferred represents excess power costs over those included in the baseline rate considering the application of PCA sharing bands.

What is the effective baseline rate at the end of the PCA Period when changes in the variable power cost components are considered?

As shown on Exhibit A-1 Power Cost Rate Updated, Section 2 of this report, when changes in variable components of the PCA Mechanism are considered the baseline rate is $45.42. The variable components increased by $1.467 from the baseline rate at the time of the Settlement, $43.953 (Exhibit A-1 Power Cost Rate, Section 1 of this report).

Will there be a rate increase as a result of this filing?

No. The deferral balance is not at a level where an increase is warranted. As noted above, the under-recovered balance deferred at the end of the PCA Period, June 30, 2003 was $4,085,328.

Please provide a brief summary of the Power Cost Adjustment Mechanism.

As authorized by the Commission, the Company's PCA mechanism accounts for differences in PSE's modified actual power costs relative to a power cost baseline. This mechanism accounts for a sharing of costs and benefits that are graduated over four levels of power cost variances, with an overall cap of $40 million (+/-) for 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 allocated 99% to the customers and 1% to the Company. See Attachment A, Stipulation, which define the specific sharing levels and conditions.

Please explain what categories of power costs are included in the PCA mechanism.

The following fixed and variable power costs are included. These costs are adjusted as described below.

Fixed Costs:

Fixed costs are the power production related costs from the most recent general case or Power Cost only review which for purposes of calculating the PCA do not change during the PCA period. These costs include the rate of return, depreciation, and property taxes for production

EXPLANATORY Q & A (cont.)

plant and specifically identified transmission plant. Other fixed costs include FERC Accounts 557 Other production expense, Hydro and Other Production O&M, and 500 KV O&M.

Variable Costs:
Actual monthly amounts recorded in FERC Accounts 501 – Steam generation fuel, 547 – Other power generation fuel, 555 – Purchased power, 447 – Sales for resale, 565 – Transmission of electricity by others as well as Orders for sales of non-core gas 45600012, 45600018, 45600035, 45600036 and 45600017 Transmission Revenue for Colstrip 1-4 lines, Third AC and Northern Intertie are included. Allowed regulatory return on amounts associated with Tenaska, Cabot and the Bonneville Exchange Power Agreement ("BEP") regulatory assets are also included in Variable costs.

Adjustments:
Adjustment per the Settlement Agreement include: 1) prudence from UE-921262, disallowance of a portion power costs associated with March Point 2 (3%) and Tenaska (1.2%); 2) Contract price adjustments have been made to limit the rate or total cost per UE-011570; 3) Colstrip Availability adjustment; 4) New resource pricing adjustment (to bring the cost of the resource to the lower of actual unit cost or embedded rate). No adjustment was required during the first year of the PCA Mechanism for either item 3 or 4 above.

Please explain how the Company has tracked PCA Mechanism activity.
The Company has detailed accounting instructions, provided in the supporting workpapers to this filing, that track PCA Mechanism activity.

Each month the Company calculates the power costs subject to PCA sharing using the same methodology shown in Exhibit B from the original PCA Mechanism filing. This monthly calculation uses the fixed costs and actual variable power costs incurred since the implementation of the Power Cost Rate plus an estimate of the power costs to be incurred by the end of the PCA period. These costs are then adjusted for the prudence disallowance for March Point 2 and Tenaska, contract price adjustments as defined in the PCA and any adjustments required for Colstrip availability.

This total of allowable costs is then compared to the allowable baseline costs and any difference is allocated to the Company or customer based on the different levels of sharing defined in the PCA Mechanism. If any of the difference between the calculated allowable costs and Baseline Power Cost is to be allocated to the customers the deferral is recorded in FERC Account 182.3, Other regulatory assets or Account 254, Other regulatory credits depending on whether the accumulated balance is a debit or credit.

Under the PCA Mechanism, the deferred amount at the time of the next PCA filing, along with the projected variable and fixed costs through the next proposed rate year would be considered in the determination of the rate change for the subsequent PCA period. Amounts deferred will be amortized to FERC Account 407.3, Regulatory debits or 407.4, Regulatory credits as they are recovered or refunded by the Company to customers.

The Company accrues interest monthly on any deferred balance (debit or credit) at the interest rate calculated in accordance with WAC 480-90-233(4). As of June 30, 2003 the Company has deferred $4,085,328 of under-recovered power costs, as shown in Section 3 of this report.

Can issues of prudence be addressed in this filing?
The Settlement Stipulation contemplates that the Commission has the opportunity to review prudence issues related to short-term purchases, resources or contracts with a term of less than two years, in the evaluation of this filing.

How does the Company manage its short-term resources?
On an ongoing basis, PSE manages its energy supply portfolio to reliably serve its retail electric customer needs at overall least cost. Depending on the availability of hydro energy, plant availability, fuel prices and load fluctuations, surplus or deficit power/gas is sold or purchased in the wholesale market. The risk and financial exposure of PSE's core energy portfolio is managed through short and intermediate-term off-system physical/financial purchases and sales and through other risk management techniques. PSE's Risk Management Committee oversees the management of the overall energy portfolio. The results of theses market sales and purchases are provided in the supporting workpapers to this filing.

Has the Company engaged in long term resource transactions (longer than two years) since the settlement that were effective in the PCA period?
No.

What is the Company's procedure regarding the sale of gas purchased for CTs but not utilized for the generation of electricity?
The decision to purchase or sell gas for power generation is based on market heat rate (the relationship of gas prices to power prices). The Company generally acquires natural gas supplies for the turbines to meet a probabilistic (100 scenarios) assessment, which includes price volatility, forced outage uncertainty, as well as retail load and hydroelectric generation variability assumptions in advance of actually needing the gas. As a means to manage the risk and financial exposure of our portfolio the Company actively manages this probabilistic position on a forward-looking basis. Specifically, if heat rates decrease we will sometimes sell off any excess natural gas and replace the assumed generation with power purchases. Conversely, as heat rates increase we will sometimes purchase additional natural gas. As we approach and then enter

EXPLANATORY Q & A (cont.)

delivery month we shift to a more deterministic method of managing risk in the portfolio and will generally purchase or sell excess gas for power.

How are the gas financial purchases or sales credited to fuel costs for gas generation plants?

The PSE gas traders may enter into financial swaps to hedge our actual costs of natural gas with various counterparties The trader has the option of taking a fixed or floating price position on the financial swaps. The financial hedging decision is determined by a number of factors including the heat rate of the plant, the market heat rate and how much physical volume will be purchased at market prices. Once the decision is made on what gas to financially hedge, a deal ticket is prepared which indicates the generation plant that will be allocated the gain or loss.

The financial deals that are used to hedge the gas used by Tenaska are allocated to FERC account 456 to offset the costs of the actual fuel that is expensed to FERC account 456.

The financial transactions that are used to hedge the gas used by Encogen and CT's are allocated to FERC account 547 to offset the costs of the fuel burned.

What transmission costs and revenues are included in the PCA?

Costs and revenues associated with four specific transmission lines are included in the PCA Mechanism. The Transmission lines included are the two at Colstrip, the Third AC and the Northern intertie. These lines bring power to PSE's system, as opposed to transmission costs that move power through PSE's system.