EXHIBIT NO. \_\_\_(JHS-8) DOCKET NO. UE-07\_\_\_/UG-07\_\_\_ 2007 PSE GENERAL RATE CASE WITNESS: JOHN H. STORY

# BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

Docket No. UE-07\_\_\_\_ Docket No. UG-07\_\_\_\_

PUGET SOUND ENERGY, INC.,

**Respondent.** 

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

**DECEMBER 3, 2007** 

Exhibit No. \_\_\_(JHS-8) Page 1 of 30

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

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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. <u>Power Cost Rate</u>: 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.

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

#### Total Revenue Requirement Table

6/4/02

<sup>&</sup>lt;sup>1</sup> References in table correspond to FERC accounts to be itemized in the Exhibits. For example, "Other Power Supply Expenses" corresponds to FERC Account 557.

Exhibit No. \_\_\_(JHS-8) Page 5 of 30

Exchange Power	Intertie,	

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. <u>New Resources:</u> 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. <u>Power Cost Only Rate Review:</u> 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 areconsistent with this docket, including power supply and other adjustments impacting then current production costs.

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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 electricresource 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.

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#### F. Miscellaneous Provisions

18. <u>Binding on Parties:</u> 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. <u>Integrated Terms of Settlement:</u> 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. <u>Negotiated Agreement</u>: 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.**

Kimberly Harris

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

Vice President of Regulatory Affairs

# WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF

By\_

Robert Cedarbaum Shannon Smith Assistant Attorneys General

# AT&T WIRELESS SERVICES, INC.

By\_

Simon ffitch Assistant Attorney General Public Counsel Section Chief By \_\_\_\_\_\_ Its \_\_\_\_\_ F. Miscellaneous Provisions

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#### PUGET SOUND ENERGY, INC.

By\_

Kimberly Harris Vice President of Regulatory Affairs

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

By\_

Simon ffitch Assistant Attorney General Public Counsel Section Chief

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SETTLEMENT TERMS FOR PCA - 8 [/BA021490098.DOC] WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF

By

Robert Cedarbaum Shannon Smith Assistant Attorneys General

AT&T WIRELESS SERVICES, INC.

#### 6/4/02

Exhibit No. \_\_\_(JHS-8) Page 10 of 30

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Vice President of Regulatory Affairs

#### PUGET SOUND ENERGY, INC.

Kimberly Harris

#### WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF

By\_

By\_

Robert Cedarbaum Shannon Smith Assistant Attorneys General

OF THE ATTORNEY GENERAL OF THE STATE OF WASHINGTON	AT&T WIRELESS SERVICES, INC.
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Simon ffitch	 Its
Assistant Attorney General	
Public Counsel Section Chief	· ·

SETTLEMENT TERMS FOR PCA -- 8 [/BAD21490098.DOC]

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JUN-04-2002 TUE 01:35 PM DAVIS WRIGHT TREMAINE

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Exhibit No. \_\_\_(JHS-8) Page 11 of 30

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PUGET SOUND ENERGY, INC.	WASHINGTON UTILITIES AND TRANSFORTATION COMMISSION STAFF
By	By Robert Cedarbaum Shannon Smith Assistant Attorneys General
PUBLIC COUNSEL SECTION, OFFICE OF THE ATTOENEY GENERAL OF THE STATE OF WASHINGTON By	ATAT WIRELESS SERVICES, INC. By The Calm C.F.M. Its Communicity Marager

Exhibit No. \_\_\_(JHS-8) Page 12 of 30

# COGENERATION COALITION OF WASHINGTON

**KROGER CO.** 

By

Donald Brookhyser V Attorney for Cogeneration Coalition of Washington

NW ENERGY COALITION and NATURAL RESOURCES DEFENSE COUNCIL

By\_

Danielle Dixon Policy Associate, NW Energy Coalition

SETTLEMENT TERMS FOR PCA -- 9 [/ngfunf85] Michael L. Kurtz Attorney for Kroger Co.

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Policy Associate, NW Energy Coal	tion, i	
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SETTLEMENT TERMS FOR PCA		÷

Exhibit No. \_\_\_(JHS-8) Page 14 of 30

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

AT&T WIRELESS SERVICES, INC.

By \_\_\_\_\_

Its \_\_\_\_

By\_\_\_

Simon ffitch Assistant Attorney General Public Counsel Section Chief

#### COGENERATION COALITION OF WASHINGTON

KROGER CO.

By\_

By\_

Michael L. Kurtz Attorney for Kroger Co.

Donald Brookhyser Attorney for Cogeneration Coalition of Washington

NW ENERGY COALITION and NATURAL RESOURCES DEFENSE COUNCIL

By

Danielle Dixon Policy Associate, NW Energy Coalition

Exhibit No. \_\_\_(JHS-8) Page 15 of 30

# Exhibit A-1 Power Cost Rate

Row		- Mulo		Test Year					
3	Regulatory Assets (Variable)	-	\$	284,728,294	-				
4	Transmission Rate Base (Fixed)		Ψ	• •					
5	Production Rate Base (Fixed)			122,217,537					
6	(FRed)	-	S	482,094,767	-				
7	Net of tax rate of return		\$	889,040,598					
8	Net of tax fale of felum			7.30%	_				
9						st Yr			
10	Regulatory Asset Recovery		•	04 077 470		IWh		Rate Year	-
11	Fixed Asset Recovery		\$	31,977,178		.677	• • •		
12	501-Steam Fuel			67,868,920		3.560	•••	69,852,738	
13	555-Purchased power			32,511,186		.705	(c)		
14	557-Other Power Exp			527,080,489		.648	(c)		
15	547-Fuel			7,447,583			•••	7,665,277	
16				61,173,325			(c)	)	
17	565-Wheeling			41,435,360			(c)	)	
18	Variable Transmission Income			(6,510,985)					
19	Hydro and Other Pwr.			51,597,583	\$ 2	2.707	(a)	53,105,787	
20	447-Sales to Others	_		(37,525,193)			(c)	)	
20	456-Subaccounts 00016 & 0001	8		1,077,379			(c)	)	
	Transmission Exp - 500KV			342,495		).018		352,506	
22 23	Depreciation fixed			40,979,607	•	2.150	(a)	42,177,446	
23 24	Amortization Regulatory Assets			15,035,627		).789	(c)	)	
24	Property Taxes	-		13,124,556	\$ C	.688	(a)	13,508,189	_
25	Subtotal & Baseline Rate		\$	847,615,110	\$ 44	.463	(b)	186,661,943	- (d)
26	Revenue Sensitive Items			0.9552337			(0)	100,000,0010	(4)
27		-	\$	887,337,947	•				
28	Test Year Load (MWH's)		•	19,063,867		nclude	e Eirm	Wholesale	
29		Before Re	NV S	Sensitive Items				ive Items	
	Power Cost in Rates with			Seriolare Rems	<u>Milei</u>	_Nev.	Sensiu	ive nems	
	Revenue Sensitive Items (the								
30	adjusted baseline				AF	5.547			
31	sum of (a) = Fixed Rate Compone	ent		9.514		.960			
32	(b) = Power Cost Rate			44.463		5.547			
33	sum of (c) = Variable Power Rate			34.949		5.587			
34	Component			04.045	50				
35 ·	•								
36	* Regulatory Assets are Tenaska,	Encogen I	Fue	Buyout and BE	D				
37									
38	(d) It is the Company's proposal to	shape the	fix	ed costs based	upon				
39	historical retail revenues shape or	historical n	non	thiv expense sh	ane "	The			
40	purpose is to prevent seasonal sw	ings in the	def	erral account	Detaile	to			
41	be determined.				- 0.000				

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# Exhibit A-2 Transmission Costs

Row			Date	DR (CR) Accumulated Deferred Income Income Tax Balance	
8 9	Colstrip Related Tra	insmission Assets			
10	Balance at:		6/30/01	(15,759,774)	
11	No deferred income	taxes associated with the 3rd AC In	tertie,	(10,100,114)	
12		d BPA Transmission Assets.			
13 14					
14	rest Period Propert	y Taxes on transmission Related As:			
16	Oregon-3rd AC Intert		Amount		
17	Montana-Transmissi		\$864,630 1,619,726		
18	Montana-Beneficial U	ise Property Taxes on BPA	1,013,720		
19	Transmission Asset	5	1,826,626		
20	Washington-Northern		127,735		
21 22	Total Property Taxe	5	\$4,438,717		
23	Wheeling Expense		14 195 000		
24			41,435,360		
25	<b>Transmission Plant</b>				
-26		· · · · · · · · · · · · · · · · · · ·			
27 28	E351	TRANS - COLSTRIP 1 & 2	AMA 6/30/01	Accum. Dep.	Depreciation Exp.
29	E353	Easements Station Equipment	685,927	264,280	17,011
30	· E354	Towers & Fidures	1,231,131	682,186	34,964
31	E355	Poles & Fixtures	14,474,343 49,007	5,917,036	374,885 774
32	E356	OH Condcutors & devices	13,158,153	39,834 5,749,080	369,744
33	E359	Roads & Trails	113,968	43,839	2,872
34	COLSTRIP 1&2 TRA	NSMISSION	29,712,529	12,696,255	800,250
35 36					•
30 37	E351	TRANS - COLSTRIP 3 & 4			
38	E352	Easements Structures & improvements	1,071,124	396,585	27,314
39	E353	Station Equipment	478,326 17,687,015	188,636	11,719
40	E354	Towers & Fidures	20,422,516	6,706,154 8,020,387	578,365 541,197
41	E355	Poles & Fidures	122,619	58,220	3,298
42 43	E356	OH Conductors & Devices	20,015,734	8,474,189	572,450
44	E359 COLSTRIP 3&4 TRA	Roads & Trails	341,015	127,820	8,730
45	OULSTRIF 304 TRA	NOMISSION	60,138,349	23,971,991	1,743,073
46		TRANS - 3RD NW-SW INTERTIE			
47	E352	Structures & Improvements	1,276,264	493 547	22.045
48.	E353	Station Equipment	31,157,075	183,547 5,529,150	22,845 716,613
49	E354	Towers & Fixtures	22,781,417	3,276,322	430,569
50	E355	Poles & Fixtures	204,200	19,787	5,268
51 52	E356 E359	OH Conductors & devices Roads & Trails	23,458,461	4,528,227	609,920
53	TOTAL 3RD NW-SW		59,215	4,141	628
54			78,936,632	13,541,174	1,785,843
55		TRANS - NORTHERN INTERTIE			
56	E351	Easements - Whatcom		-	-
57 58	E354	Towers & Fixtures-Whatcom	5,744,097	533,604	106,840
56 59	E355 E356	Poles & Fixtures-Whatcom	11,219	1,702	289
60	E355	OH Conductors & Devices-Whatc Poles & Fixtures-Skagit	7,460,099	904,353	193,963
61	E356	OH Conductors & Devices-Skagit	3,398,685 5,142,699	416,680	87,686
62	TOTAL NORTHERN	INTERTIE	21,756,799	<u>501,239</u> 2,357,577	<u> </u>
63				2,001,011	922,700
64	Total Transmission		190,544,309	52,566,998	4,851,654
65 66	Less Accumulated Depre				
67	Accumulated Depre Deferred Taxes	ciation	52,566,998		
68	Transmission Rateba	ase	<u>15,759,774</u> 122,217,537	•	
			142,217,337		

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### Exhibit A-3 Colstrip Fixed Costs

	A-3 Colstrip Fixed Cost						
Revenue	Requirement for Colstrip						A-3 Page 1
	Plant	647,044,432					
	Accumulated Depreciation	(329,162,409)					
	Deferred Taxes	(93,634,221)					
	Net Plant	224,247,802					
	Rate of Return (net of Tax)	7.30%					
	Revenue Requirement after tax	16,370,090	·				
	Plant Revenue Requirement	25,184,753	(Adjusted for F	ederal Tax)			
	Expenses	52,329,884					
	Total Revenue Requirement	77,514,637	(before revenu	e sensitive item:	\$)		
Support for	Revenue Requirement - Ratebase						
FERC	DESCRIPTION	30-Jun-00	30-Jun-01	13 MONTH AMA	ANNUITY RATE	ANNUALIZED DEPRECIATION	ACUMM. DEPF 06/30/2001
	COLSTRIP #1			<b>.</b>			
E311	Structures & Improvements	6,931,939	7,097,390	7,021,558	3.03%	212,753	4,519,38
E312	Boiler Plant Equipment	46,965,650	48,224,007	47,159,778	3.12%	1,471,385	30,962,57
E314	Turbo Generating Units	12,437,937	12,437,937	12,437,937	3.29%	409,208	8,005,68
E315	Accessory Electric Equip.	7,042,053	7,043,604	7,042,893	2.71%	190,862	4,440,85
E316	Misc. Power Plant Equip.	365,117	426,565	398,402	3.87%	15,418	215,98
	TOTAL	73,742,696	75,229,503	74,060,568	3.11%	2,299,626	48,144,48
	COLSTRIP #2						
E311	Structures & Improvements	5,317,757	5,573,640	5,456,360	3.06%	166,965	3,343,89
E312	Boiler Plant Equipment	39,821,935	40,460,296	40,167,714	3.05%	1,225,115	26,457,59
E314	Turbo Generating Units	12,178,755	12,519,462	12,363,305	3.26%	403.044	7.691.61
E315	Accessory Electric Equip.	4,536,518	4,592,474	4,566,828	2.69%	122,848	2,797,27
E316	Misc. Power Plant Equip.	365,931	427,379	399,215	3.61%	14,412	217,88
	TOTAL	62,220,895	63,573,251	62,953,422	3.07%	1,932,384	40,508,26
	COLSTRIP 1 & 2 COMMON						
E311	Structures & Improvements	30,345,256	31,983,349	31,232,556	3.16%	986,949	18,788,55
E312	Boiler Plant Equipment	8,623,422	8,679,337	8,653,709	3.18%	275,188	5,533,21
E314	Turbo Generating Units	3,918,858	3,918,858	3,918,858	3.31%	129,714	2,382,31
E315	Accessory Electric Equip.	2,377,984	2,420,179	2,400,840	3.07%	73,706	1,334,87
E316	Misc. Power Plant Equip.	6,235,545	6,561,728	6,412,227	3.82%	244,947	3,136,06
	TOTAL COLSTRIP 3	51,501,064	53,563,451	52,618,190	3.25%	1,710,504	31,175,02
E311	Structures & Improvements	38 830 645			• • • • • •		44 800 -
E311	Structures & Improvements Boiler Plant Equipment	28,829,642	28,882,948	28,858,516	2.45%	707,034	14,566,34
E314	Turbo Generating Units	113,898,277	115,756,485	113,618,072	2.68%	3,044,964	57,262,23
E315	Accessory Electric Equip.	32,936,825	33,180,681	33,068,914	2.97%	982,147	14,166,23
E316	Misc. Power Plant Equip.	6,401,615	6,401,615	6,401,615	2.47%	158,120	2,874,15
	TOTAL	454,762 182,521,121	480,140	468,508	2.86%	13,399	210,03
	COLSTRIP 4	102,021,121	1041101-003	182,415,625	2.69%	4,905,664	89,079,00
E311	Structures & Improvements	26,542,394	26,595,701	26,571,269	2.54%	674 040	11,552,30
E312	Boiler Plant Equipment	99,709,843	100,508,440			674,910 2 753 916	
E314	Turbo Generating Units	27,895,777	28,602,598	100,142,416	2.75%	2,753,916	43,898,28
E315	Accessory Electric Equip.	5,589,362	5,596,707	28,278,638	2.94%	831,392	10,813,3
E316	Misc. Power Plant Equip.	650,784	676,163	5,593,341	2.52%	140,952	2,163,8
	TOTAL	160,388,160	161,979,609	<u>664,531</u> 161,250,195	2.79%	<u>18,540</u> 4,419,710	277,8 68,705,6
	COLSTRIP 3 & 4 COMMON	100,000,100	101,979,009	101,230,133	2.1470	4,413,710	00,103,6
E311	Structures & Improvements	71,951,771	72,034,845	71,996,769	2.33%	1,677,525	35,209,2
E312	Boiler Plant Equipment	20,855,440	20,915,298	20.887,863			10,585,0
E314	Turbo Generating Units	274,553	274,553	20,667,663	2.48% 2.62%	518,019 7,193	125,8
E315	Accessory Electric Equip.	7,706,935	7,748,971	7,729,705	2.82%		3,422,0
E316	Misc. Power Plant Equip.	4,861,282	5,098,460	4,989,753	2.31%		
	TOTAL	105,649,981	106,072,127	105,878,643	2.79%		2,083,8 51,426,0
	COLSTRIP 1-4 COMMON	100,049,901	100,072,127	103,070,043	2.30%	2,320,307	51,420,0
E316	Misc. Power Plant Equip.	253,865	253,865	253,865	3 AEN	6,245	123,8
	TOTAL	253,865	253,865	253,865	2.46%		123,8
						0.243	14.3.0
COLSTRIP		•	200,000	200,000		-,-	
	COMMON FERC ADJ. DEF DEPR FERC ADJ.	8,316,981 2,449,668	200,000	200,000	2.4070	-,-	

PCA Collaborative

# Exhibit A-3 Colstrip Fixed Costs

69	Support for	Revenue Requirement - Expen	ses
70			Amount before
71	Order	Description	Prod. Adj.
72	50004011	1&2 Sup & Eng	76,685
73	50005011	3&4 Sup & Eng	108,581
74	50204001	1&2 Steam Exp	1.217.034
75	50205001	3&4 Steam Exp	624,831
76	50504001	1&2 Elec Exp	(208,933)
77	50505001	384 Elec Exp	(223,913)
78	50604001	1&2 Misc Exp	3,320,269
79	50605001	3&4 Misc Exp	2,515,968
80	50605002	3&4 Steam	(2,399)
81	50704001	1&2 Rents	95.991
82	50705001	3&4 Rents	131.692
83	51004001	1&2 Maint Supv	669,151
84	51005001	3&4 Maint Supv	539,405
85	51104001	1&2 Maint of Struct	405,072
86	51105001	3&4 Maint of Struct	373,938
87	51204001	1&2 Maint of Boiler	4,902,128
88	51205001	3&4 Maint of Boiler	5,967,278
89	51304001	1&2 Maint of E Plant	(178,069)
90	51305001	3&4 Maint of E Plant	705.533
91	51404001	1&2 Maint of Misc	4,578,888
92	51405001	3&4 Maint of Misc	1,159,196
93		Property Taxes-Montana	6,027,509
94		Electric Energy Tax	1,729,406
95	403,0000	Depreciation	17.794.640
96		• • • • • • • • • • • • • • • • • • • •	\$52,329,884
			442,020,004

A-3 Page 2

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Exhibit No. \_\_\_(JHS-8) Page 19 of 30

# Exhibit A-4 Production Adjustment UE-011570

**PAGE 2.21** 

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

LINI	-	PRO FORMA	PRODUCTION	FIT	
NO.	DESCRIPTION	AMOUNT	2.84%	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	<u> </u>		,	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	
10	DEPRECIATION PRODUCTION PROPERTY	7			
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		59,913	
19	ELECTRIC ENERGY TAX	1,729,406		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	
<b>2</b> 6 <sub>.</sub>					
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			After Production Adj.
32	BPA POWER EXCHANGE INVESTMENT		sum of L32 thru	293 050 941	284,728,294
33	TENASKA REGULATORY ASSET	229,424,000		2,00,000,011	201,720,271
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)			Less Regulatory Assets
43	ADJUSTMENT TO RATE BASE	789,237,403	(22,414,342)	766 823 061	482,094,767
		,,	(, 117, 372)		704,077,707

# 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					INCREASE
NO.	DESCRIPTION	ACTUAL	TUAL PROFORMA		(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)	
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)	• •
10	SUBTOTAL	\$ 806,261,151	S	674,237,946	<b>\$</b> (132,023,205)
11			-	· · · <b>,</b> · <b>,</b> -	· · · · · · · · · · · · · · · · · · ·
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	S	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	, ,			<b>\$</b> 1,810,899,515
20					,,,,
21	INCREASE(DECREASE) FIT @	35%			633,814,830
22	INCREASE(DECREASE) NOI				\$ 1,177,084,685
					-,,,

				2	Jul 02 - Jun 03	Explanation or source
Return on Fixed RB	e			\$	69,852,738	from Exhibit A-1 line 11 - production and transmission ratebase adjusted to Rate Year
Other Fixed Costs Subtotal Fixed Costs	ŝ			s	116,809,205 186,661,943	rom Exmont A-1 mice 14, to 21, 42, 624 (201, 17) up and Uniter Frod. Dam, 500 AV Com Depreciation fixed, Property tax) adjusted to Rate Year
Total Variable Component Actual Steam Oper. Fuel	iponent Actual el 501	- <u></u> -	illustrative est.	\$	33,461,494	SAP - actual
Other Pwr Gen Fuel			illustrative est.		55,009,484	SAP - actual
Other Elec Revenues Durchase Douter	nues 45600012, 18		illustrative est. Illustrative est		(165,000) 538 456 775	SAP - actual Non Core Gas (sales) / purchases orders 45600012, 45600018 SAP - actual
Sales to Other Util		=	illustrative est.		(35,448,055)	SAP - actual
Wheeling		-	illustrative est.		43,496,800	SAP - actual
Transmission Revenue Regulatory Assets	evenue 45600017 ts		illustrative est. Illustrative est.		(5,000,000) 36,867,841	SAP - actual 1 ransmission revenues on 3rd AC, Northern Interite, Constrip lines from Exhibit D line 35. Amortization and return on regulatory assets for PCA period
SUBTOTAL before Adjustments	Adjustments		642,456.32	5	853,341,232	
Adjustments:			te e suite de la	•		Drutana adi = 20 4 Marah Dt 2 animatata and 4 20 4 Tanaha mamada
Prudence from UE-921262 Contract price adjustment	-921262 stment		illustrative est. illustrative est.	•	(2c1,004,429)	Procence act, = 3.3 • March PL / payments, and 1.4.3 • Feliaska payments from Exhibit E line 42
Colstrip availability adjustment	adjustment	72	illustrative est.		(5,712,733)	from Exhibit F line 40
New resource pricing adjustment	ng adjustment	-	illustrative est.		(388,500)	from Exhibit G line 38
Subtotal Adjustments	ıts			\$	(9,455,814)	
Total allowable cost	<u>ist</u>			S	843,885,418	
PCA period delivered load	d load	¢	est. actual		19.110.518	Actual delivered MWh during PCA period = Total load net of losses
Baseline Power Cost	<u>ost</u> \$44.463	)		~	849,710,975	Base line rate from Exhibit Å-1 line 25
						to Exhibit C column (C). A portion of the imbalance will be allocated to firm wholesale
Imbalance for Sharing	Du		•	\$	(5,825,557)	customers based upon the allocation used in the most recent Docket approving rate spread
positive is potential cust	positive is potential customer surcharge, negative is potential customer credit	ential custo	omer credit			
Company's Share	band limit +/-					
First band - deadband	nd \$ 20,000,000	100% 100%	(5,825,557)	•	(5,825,557)	
Zha Bang - next			• •	•	ı •	
Sta band - next 4th Band greater than		2°2		• ••	•	
Subtotal Company Share before Cap	Share before Cap		(5,825,557)	\$	(5,825,557)	to Exhibit C column (G)
Customer Share (deferral account)	deferral account)			\$	•	to Exhibit C column (D)

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Exhibit B

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PCA Exhibits A-G v3.xls

Exhibit No. \_\_\_(JHS-8) Page 21 of 30

Page 1 c

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Exhibit C - Application of \$40 million Cap

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 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 set for refund or collection at that time. 20070770 20070700 2007

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9 10	Example: 1	e: 1		First	First year per draft	er c		xhibit	exan	Exhibit examples; next 3 years high power costs	ixt 3	l years h	gh pc	wer	costs					]		
11				\$ In Millions	llions																	
42			(c)		â		(E)	Ē		(C)		(H)		ε	દ		(X)	(L)		(W)		
		<u>}</u>	intralance for	Customer Annual Share	omer Share	S ≰ S	Customer Annual Shora Auor	End Period Customer Deforred	eriod			Potential transfer (to) Company	Com	hany	End Period		Company	•	•	Annual Change	thange	
13 13		Ü	Sharing Ex. B line 33	= "Deferral" Ex. B line 43	ferral" ine 43	Cap	Cap at 99%	Balance		Annual Share Ex. B line 41	5 <u>5</u> 5	/ II MII customer	Capi	Cap at 1%	Share		Accum Share Accum. Amount in Amount over w/o Cap Over Cap Cap	Accum. Amot Over Cap	Cap	in Amount Cap	p over	
15									-							┼─					]	
16	PCA Yr #1	*	(5.83)	~		\$	•	\$	•	<b>\$</b> (5.1	(5.83) \$	•	\$	٠	\$ (5.8	(5.83)	(2:83) \$	47	,	ŝ		
17	PCA Yr #2	<b>\$</b>	30.00	•	5.00	\$	•	*	5.00	\$ 25.(	25.00 \$	•	ŝ	1	\$ 19.17	2 \$	19.17	••	•	\$	ı	
18	PCA Yr #3	<b>%</b>	30.00	\$	5.00	•	4.13	*	14.13	\$ 25.0	25.00 \$	\$ (4.17) \$		0.04	\$ 40.04	4	44.17	\$	4.17	•	4.17	
¢ 8	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	
8 73	Check	\$	84.2 OK	¥				\$	43.9						\$ 40.3	]_						

Exhibit C Examples over 4 pa

PCA Exhibits A-G v3.xls

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Exhibit C - Application of \$40 million Cap

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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 Customer at end of the fourth year, and any remaining deferred balances associated with the cap are 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 • set for refund or collection at that time. 

Example: 2	ple:	2	Four year	year . lions	Four year cost scer s in Millions	nario	discu	าario discussed at May 23rd PCA Collaborative	May 2	3rd PCA	V Colli	abora	tive					
	•	(c)	<u>(</u> )		(E)		(F)	(B)		(H)		ε	ົ		X	(ר)		(W)
		Imbalance for Sharing Ex. B line 33	Customer Annual Share = "Deferral" Ex. B line 43	mer Share erral" 1e 43	Customer Annual Share over Cap at 99%		End Period Customer Deferral Balance	Company Annual Share Ex. B line 41	ny hare 941	Potential transfer (to) Company End Period <i>I</i> from share over Company customer Cap at 1% Share	) Con shar Cap	Company share over Cap at 1%	End Period Company Share		Company Accum Share w/o Cap	Annual Change Accum. Amount in Amount over Over Cap Cap	P ount i	Annual Change in Amount over Cap
PCA Yr #1	1	\$ 30.0	\$	5.0	, v	••	5.0	••	25.0	•	÷	•	<b>\$</b> 25	25.0 \$	25.0	~		
PCA Yr #2	5	•	**	٠	•	\$	5.0	_~		•	\$	•	\$ 25	25.0 \$	25.0	•	••	1
PCA Yr #3	5	\$ (100.0) \$		(64.0)	י א	49	(29.0)		(36.0)	•	••	•	<b>\$</b> (11,	(11.0)	(11.0)	•	••	,
PCA Yr #4	44	\$ 36.0	\$	8.0	•	••	(51.0) \$		28.0 \$	، دە	••	٠	\$ 17.	17.0 \$	17.0	•	•7	•
Check		(34.0) OK	ð			\$	(51.0)						\$ 17.0	٦٥				

Exhibit No. \_\_\_(JHS-8) Page 23 of 30

PCA Exhibits A-G v3.xls

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Exhibit C - Application of \$40 million Cap

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 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 set for refund or collection at that time. 

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36 37	Example: 3	3		Thre \$ in M	Three high \$ in Millions	Three high power c \$ in Millons	cost	years f	ollowe	d by v	cost years followed by very low power cost year.	wod	er cosi	t yea	L.						
88			(c)		ê	(E)		(F)	( <u>9</u>	(6	(H)		Ξ		5	(X)		5		Ŵ	=
				(		Customer		End Period			Potential	Ĩ									
		<u></u>	Imbalance for	Annua	Customer Annual Share	Annual Share ove		Customer Deferral	Company	pany	transfer (to) / from	ي م	Company share over		End Period Company	Company Annual Change Accum Share Accum. Amount in Amount over	'y lare ≜	Accum. Ar	mount	Annual Change in Amount over	Change nt over
<b>6</b> 8		Ĕ	Sharing Ex. B line 33	۳. ۳. ۳.	= "Deferral" Ex. B line 43	Cap at 99%		Balance	Annual Share Ex. B line 41	Annual Share Ex. B line 41	customer		Cap at 1%		Share	w/o Cap	۵	Over Cap	ap	Cap	ē.
42	PCA Yr #1	\$	30.0	\$	5.0 \$	•	\$	5.0	\$	25.0 \$	•	\$	•	\$	25.0	•	25.0	~	•	\$	•
43	PCA Yr #2	\$	100.0	\$	64.0 \$	\$ 20.8	<b>\$</b> ≯ €0	89.8	\$	36.0	\$	(21.0) \$	0.2	\$	40.2	<b>\$</b>	61.0	~	21.0	\$	21.0
44	PCA Yr #3	\$	36.0	*	8.0	\$ 27.7	*	125.5	\$	28.0	\$	(28.0) \$	0.3	••	40.5	<b>8</b>	89.0	~	49.0	\$	28.0
45 46	PCA Yr #4	\$	(100.0) \$	\$	(64.0) \$	(35.	<b>\$</b> (9	25.9	•	(36.0) \$		36.0 \$	(0.4) \$	•	40.1	<b>\$</b>	53.0	•	13.0	\$	(36.0)
	Check	••	66.0 OK	¥			\$	25.9						~	<b>\$</b> 0.1						

# Exhibit No. \_\_\_\_ Page 24 of 30 (JHS-8)

PCA Exhibits A-G v3.xls

EX. D III16 33       EX. D III16 43         \$ (30.0)       \$ (5.0)       \$ (5.0)         \$ (100.0)       \$ (64.0)       \$ (20.8)       \$ (80.8)         \$ (36.0)       \$ (8.0)       \$ (27.7)       \$ (125.5)         \$ 100.0       \$ 64.0       \$ 35.6       \$ (25.9)	Customer       End Period       Potential         Customer       Annual       Customer       Annual         Customer       Annual       Customer       Annual         Imbalance for       Annual Share       Share       Share       Accum       Amount over         Sharing       = "Deferral"       Cap at 99%       Balance       Annual Share       Aver       Company       Accum       Amount over         E.x. B line 33       Ex. B line 43       Ex. B line 41       Ex. B line 41       Vio Cap       Over Cap       Cap	(C) (D) (E) (F) (G) (H) (I) (J) (K) (L) (M)	Similiar to example \$ In Millions	Overall Cap For Four Year Period: As a separate limit, calculated per the sharing bands discussed in the settlem Customer and 1% of costs and benefits to Company. The set for refund or collection at that time.         Example: 4       Similar to example and settlem customer         Example: 4       Similar to example and settlem customer         Contraction at that time.       Customer and 1% of costs and benefits to Company. The set for refund or collection at that time.         Example: 4       Similar to example and settlem customer         Cost       D)         (C)       Customer         Annual time.         PCA Yr #1       \$ (30.0)         PCA Yr #2       \$ (100.0)         PCA Yr #3       \$ (100.0)         PCA Yr #4       \$ 100.0         PCA Yr #4       \$ 100.0         PCA Yr #4       \$ (100.0)         PCA Yr #4       \$ (20.0         PCA Yr #4       \$ (20.0	ap For Fo and 1% o and 1% o and 1% o EX. B EX. B Shi EX. B	C) C	And time.       Annual       = "Def.       = "Def.       5       5	ar to e litons mer Share erral he 43 (5.0) (64.0) (8.0)	mpany. Xamp Xamp Share (E)		p is remov p is remov nut fortu (F) (F) (F) (F) (E) (E) (E) (125.5) (25.9)	nes are       Compa       Annual S       S       S	revers my hare 25.0) \$ 36.0) \$ 36.0) \$ 36.0 \$ 36.0 \$	rth year, a ed with (H) (H) / from customer 21.0 28.0 (36.0)	any any a share share share s s s s s s s s s s s s s s s s s s s	emainii cost over t1% (0.2) 1 0.4 5	ig deferred years fol (J) (J) (J) (J) (J) Share (A0.2) (40.5) (40.1)	balances assoc lowed by a l (K) (K) (K) (K) (K) (K) (K) (K) (K) (K)	ated with the ated with the ated with the ated with the ated of the ated at the at the ated at the atted at the ated at the ated at the ated at the atted at the atte	ear. ear. umt in Annu 0) \$ .0) \$	(M) Mual Change mount over Cap (21.0) 36.0
\$ In Millitons     (D)     (E)     (F)     (G)     (H)     (I)     (J)     (K)     (L)       (D)     (E)     (F)     (G)     (H)     (I)     (J)     (K)     (L)       (D)     (E)     (F)     (G)     (H)     (I)     (J)     (K)     (L)       (Customer     Annual     Customer     Potential     Potential     Annual     Annual       Annual Share     Over     Deferral     Company     I from     share over     Company     Annual       = "Deferral"     Cap at 99%     Balance     Annual Share     customer     Company     Annual	\$ in Millions (D) (E) (F) (G) (H) (I) (J) (K) (L)	\$ In Millions	ominiar to example	stomer t for refu	and 1% o und or coll :. 4	ection at the	Simila	ir to e	mpany.		ut fortui	nes are	revers	ed with	3 low	emainii cost	ig deferred	balances assoc lowed by a	ated with the o igh cost y	abrare apare car.	
or Four Year Period: As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumutative net balance, a the settlement terms for the PCA. If this cap is exceeded, sharing thereafter is adjusted to 99% 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 a or collection at that time. 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 a or collection at that time. 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 a or collection at that time. Similar to example 3, but fortunes are reversed with 3 low cost years followed by a high cost year for the fourth is in Millions (C) (D) (E) (F) (G) (H) (I) (J) (J) (K) (L) (L) (L) (D) (L) (J) (K) (L) (L) (D) and Customer End Period transfer (to Company End Period Customer End Period transfer (to Company End Period Company Accum Share Share over Deferral Cap at 99% Balance for Annual Share Company I from share over Company Wo Cap Over Cap Over Cap	Or Four Year Period: As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumutative net balance, as 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 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 or collection at that time. Similar to example 3, but fortunes are reversed with 3 low cost years followed by a high cost year. (C) (D) (E) (C) (D)	I Cap For Four Year Period: As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumutative net balance, as ted 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 the rand 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 refund or collection at that time. The cap is removed at end of the fourth year, and any remaining deferred balances associated with the cap are refund or collection at that time.	I 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 ted 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 her 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 refund or collection at that time.			ur Year P	'erlod: / ds discu d benefit	As a set ssed in s to Co	parate li	mit, the Bernent The ca	Company'	te share of I the PCA. If the at and o	power of this cap if the fou	osts/benef is exceed	its will n ied, shar	ot excer ing the	od a \$40 mi	llion (+/-) cumuta ljusted to 99% o	tive net baland f costs and be	8 8	r

Exhibit C Examples over 4 pac

PCA Exhibits A-G v3.xls

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Exhibit No. \_\_\_(JHS-8) Page 25 of 30

A Chook Buyout         Interest 20015         Amort 20015         PerA (Iul-Uul) (1/71,000)         PerA (Iul-Uul) (1/71,000)         Return + Amort 20035           20015         20015         1.2,580,00         (1/25,000)         (1/25,500)         (1/26,500)         (1/26,100)         (1/26	Row											
2000         12,568,000         Tables         Amoritation         Balance           2001         2         723,000         712,000)         12,266,000         12,266,000         12,461,030         14,460           2003         5         -         731,000         14,1000)         12,266,000         11,1716,000         5,398,400         7,249,400         5         27,614         205,4           2004         -         -         1,768,000         3,448,000         1,276,000         3,398,408         5         666,044         205,4           2005         -         -         2,163,000         7,285,000         1,1276,000         3,398,408         5         666,044         27,491,003         5         27,614         00         5         5         27,614         00         5         5         0         11,276,000         3,398,408         5         666,044         7,305,400         13,756,000         2,398,408         5         57,614         205,433         5         7,305,433         5         7,491,403         5         27,614         205,512         4,671,400         200,512         2,474,402         5         27,614         205,512         4,671,402         200,503         2,144,400         11,972,900	4	Cabot Buyout					PCA	Jul-Jun)				
2000       72,5000       72,0000       72,965,000       12,945,000       12,945,000       12,945,000       12,945,000       12,941,033       \$ 911,945       \$         2003       5       77,000       1,256,000       1,296,000       12,956,000       9,338,408       \$ 815,476       \$         2005       5       77,000       1,740,000       1,256,000       1,2491,033       \$ 911,945       \$         2005       5       737,000       1,2491,000       1,256,000       1,238,500       7,278,408       \$ 815,476       \$         2005       5       737,000       1,255,000       2,383,600       7,228,408       \$ 577,614       \$ <t< td=""><td>ŝ</td><td></td><td></td><td>Interest</td><td></td><td></td><td><u>Amortization</u></td><td>Ratebase (AMA)</td><td>7.30%</td><td>נצו</td><td><u> Return + Amoi</u></td><td>رىيە</td></t<>	ŝ			Interest			<u>Amortization</u>	Ratebase (AMA)	7.30%	נצו	<u> Return + Amoi</u>	رىيە
2001 5 - 72,000       (741,000)       12,954,000       (1,239,500)       11,710,908       5 815,475       5         2003 5 - 7,1,000       (1,776,000)       1,275,000       (1,239,500)       11,710,908       5 815,475       5         2004 5 - 7       2003 5 - 7       2,143,000       4,571,000       (1,768,000)       9,443,000       (1,239,500)       7,238,408       5 666,044       5         2005 5 - 7       2,155,000       (1,768,000)       4,571,000       (1,236,500)       7,238,408       5 666,064       5         2005 5 - 7       2,155,000       (1,235,000)       2,743,000       (1,235,000)       7,228,408       5 577,574       5         1998 5 215,000,000       8,744,000       2,645,000       (1,733,000)       213,570,000       213,570,000       213,574,000       15,324,000       15,324,000       15,324,000       15,324,000       15,324,000       15,324,000       15,324,000       15,324,000       15,324,000       15,324,000       16,1773,950       3       23,235,125       14,374,1552       3       23,275,125       14,374,1552       3       3       23,256,620       3       23,256,633       3       23,275,125       14,374,1552       3       23,275,125       14,374,1552       3       23,275,125       14,374,1552	9		12,588,000	209,000		-						
2003 5       731,000       (1,776,000)       12,655,000       12,491,033       311,945       5         2003 5       -       (1,403,000)       91,410,000       (1,565,500)       91,391,003       5       815,415       5         2004 5       -       (1,740,000)       7,285,000       (1,565,500)       91,391,003       5       815,416       5         2005 5       -       -       (2,1730,000)       7,285,000       (1,525,500)       7,283,400       5       515,614       5	2	2001 \$	·	720,000		12,964,000						
2003 5	ø	2002 \$	•	731,000	(1.070,000)	12,625,000	(1,239,500)	12,491,033				10
2004 5       -       (1,768,000)       9,448,000       (1,768,000)       9,398,408       \$ 686,084       \$         2005 5       -       (2,64,000)       7,285,000       7,285,000       7,288,008       \$       527,574       \$         2005 5       -       (2,64,000)       7,785,000       7,285,000       7,285,000       \$       527,574       \$       \$       \$       527,574       \$ <t< td=""><td>ი</td><td>2003 \$</td><td>1</td><td></td><td>(1,409,000)</td><td>11.216.000</td><td>(1,588,500)</td><td>11,170,908</td><td></td><td></td><td></td><td>6</td></t<>	ი	2003 \$	1		(1,409,000)	11.216.000	(1,588,500)	11,170,908				6
2005 5	6	2004 \$		•	(1,768,000)	9,448,000	(1.965,500)	9.398.408	_			
2006 5       -       (2,614,000)       4,671,000         1998 5       215,000,000       8,754,000       (1,952,000)       23,653,000       23,653,000       26,734,000       21,652,000       21,652,000       21,652,000       21,652,010       21,652,010       21,652,010       21,652,010       21,652,010       21,652,512       51,544,000       214,632,000       214,652,512       51,544,000       214,652,512       51,544,000       214,532,000       214,552,512       51,555,513       51,555,514,600       214,532,313,334,000       214,552,512       51,555,513       51,555,513       51,555,514,512       51,555,512       51,555,512       51,555,512       51,555,512       51,555,512       51,555,512       51,555,512       51,555,512       51,555,512       51,55	11	2005 \$	•	•	(2, 163,000)	7.285.000	(2.388.500)	7.228.408				
Tenaska       Tenaska         1999 5 - 000 5 - 000 234,75000 (1,952,000) 226,734,000 575,000 230,720,000 236,734,000 54,63,000 236,734,000 54,63,000 236,734,000 54,63,000 236,747,952 5       8,735,000 (1,952,000) 236,73,000 236,747,952 5         2001 5 - 0,000 (1,924,000) 231,576,000 (1,924,000 516,747,952 5       8,734,000 (1,924,000 236,747,952 5       5,143,747,952 5         2003 5 - 0,000 (1,924,000) 231,576,000 (1,924,000 236,747,952 5       8,749,000 (1,924,000 236,570 00) 237,576,551 24,487,482 5       5,14,637 313,571,759 5         2004 5 - 0,017 5 - 0,0115,5000 (16,540,000) 165,512 514,637 313,571,759 5       20,1437 4000 20,165,520 00) 237,555,512 31,874,822 5       5,14,637 313,571,759 5         2005 5 - 0,017 5 - 0,000 156,540 000 156,540 000 156,541 333,000 156,541 3,377,551 3,13,571,779 5       20,1437 3,13,571,779 5       5,94,4637 3,13,571,779 5         PEP       2001 200 165,640 000 156,540 000 156,560 001 165,551 3,14,677 3,13,571,779 5       3,752,552 00 3,1755,551 3,13,571,779 5       3,772,924 5       5,746,007 3,14,577 4         2002 2003 2 2,256 200 37,135 3,376,551 3,14,677 3,13,571,779 5       3,526,520 3,7755,551 3,14,577 7,759 5       3,772,924 5       5,746,477 5         2001 2 2002 2 2003 2 2,556 200 37,056 200 37,056 200 37,056 203 3,256,520 3,7755,550 3       3,752,520 3,7526,520 3,7755,520 3,7755,520 3,7556,520 3,7755,520 3,7755,520 3,7755,520 3,7556,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7556,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,7755,520 3,775	12	2006 \$	,	·	(2.614.000)	4.671.000						
Tenasta       Tenasta         1998 \$ 215,000,000       8,754,000       221,802,000       221,802,000       2365,000       226,734,000       8,745,000       8,745,000       8,745,000       3,653,000       231,576,000       3,653,000       231,576,000       3,653,000       231,576,000       3,653,000       231,576,000       3,653,000       231,576,000       3,653,000       231,334,000       233,34000       233,352,43       3,413,571,769       5       200       200,32       2,526,5200       41,637       3,135,71,769       5       200       200,200       20,252,65200 <t< td=""><td>13</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></t<>	13											
1998       \$ 215,000,000       8,754,000       (1,952,000)       226,734,000       (3,653,000)       236,734,000       (3,653,000)       236,734,000       (3,653,000)       236,734,000       (3,653,000)       236,734,000       (3,653,000)       236,734,000       (3,653,000)       236,734,000       (3,653,000)       236,734,000       (3,654,000)       (3,656,000)       236,734,000       (3,652,512       (3,632,512       (3,16,974,952       5       (1,794,000)       204,45,000       216,544,000       216,747,952       5       5       (1,794,000)       204,45,000       216,544,000       216,747,952       5       5       215,255,512       314,671,637       313,571,769       5       203,755,512       314,674,7952       5       203,755,512       314,674,7952       5       203,755,512       314,674,7952       5       203,755,512       315,71,769       5       203,755,512       314,574,7952       5       203,755,512       314,574,7952       5       203,755,512       314,574,7952       5       203,755,512       314,574,7952       5       203,755,512       314,574,7952       5       203,755,512       314,574,7759       5       203,755,512       314,56,717,593       2       203,755,512       314,55,71769       5       2       2       2       2       2       2	14	Tenaska	•					-				
1999 5       8,795,000       (3,863,000)       226,734,000       333,4,000       239,1576,000       316,747,952       5         2000 5       6       8,349,000       (5,463,000)       231,576,000       (13,323,000)       231,571,7952       5         2003 5       -       8,749,000       (14,749,000)       231,6907,000       (13,334,000)       223,44,000       516,747,952       5         2003 5       -       -       (14,744,000)       204,163,000       (19,275,512       514,882       5         2004 5       -       -       (14,744,000)       204,163,000       (16,226,000)       203,765,512       514,882       5         2005 5       -       -       (14,744,000)       204,1630       119,261,500       186,275,12       513,571,759       5         2005 5       -       -       (14,744,000)       206,160       186,255,000       (19,261,500)       186,94,333       5       571,759       5	15		215,000,000	8,754,000	(1,952,000)	221,802,000						
2000 \$ -       8,849,000       (5,453,000)       239,120,000       239,120,000       239,1357,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,424,000       239,733,000       (13,334,000)       239,424,000       239,733,000       239,424,000       239,733,523,512       54,555,512       54,556,512       54,556,529       47,569,213       51,135,941       53,75,417       5         2003       2004       2,556,6200       13,556,6200       13,526,6200       14,1602,518       3,475,417       5         2003       23,556,6200       3,135,662,010       13,556,6200       3,705,518       3,475,477       5       2       2       2 <td>16</td> <td>1999 \$</td> <td>•</td> <td>8,795,000</td> <td>(3,863,000)</td> <td>226,734,000</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td>	16	1999 \$	•	8,795,000	(3,863,000)	226,734,000						
2001 \$ -       8,838,000       (7,382,000)       231,576,000       239,424,000       516,747,952       \$         2002 \$ -       8,749,000       (9,494,000)       230,831,000       (10,709,000)       229,424,000       \$16,747,952       \$         2003 \$ -       -       (11,924,000)       204,153,000       (16,328,000)       203,155,512       \$14,874,882       \$         2004 \$ -       -       (11,924,000)       186,540,000       19,256,100       185,514,637       \$13,571,769       \$         2005 \$ -       -       -       (17,474,000)       186,540,000       19,256,100       186,541,637       \$13,571,769       \$         2005 \$ -       -       -       (20,615,000)       186,5640,000       19,256,512       \$14,874,882       \$         2006 \$ -       -       (17,474,000)       165,640,000       165,640,000       19,256,520       \$11,35,941       \$       373,574,775       \$         2001       205,6520       51,135,884       (3,526,620)       51,135,941       \$       373,5924       \$	17	2000 \$	•	8,849,000	(5,463,000)	230,120,000						
2002 \$ -       8,749,000       (9,494,000)       230,831,000       (10,709,000)       229,424,000       516,747,952       \$         2003 \$ -       -       (11,924,000)       218,907,000       (13,334,000)       218,555,512       \$15,954,333       \$         2006 \$ -       -       (11,924,000)       165,640,000       185,514,637       \$13,571,769       \$         2006 \$ -       -       (17,908,000)       186,255,000       (19,261,500)       185,914,637       \$13,571,769       \$         2006 \$ -       -       (17,908,000)       186,25,600       (19,261,500)       185,914,637       \$13,571,759       \$         2007       2001       155,640,000       155,640,000       155,640,000       155,640,000       19,261,500       19,526,520       \$113,5941       \$3,732,924       \$         2001       2022       54,652,518       3,526,620       47,609,278       \$3,475,477       \$	18	2001 \$	1	8,838,000	(7,382,000)	231,576,000						
2003 \$ -       -       (11,924,000)       218,957,000       (13,334,000)       218,555,512       515,954,333       \$         2004 \$ -       -       (14,744,000)       204,163,000       (16,326,000)       203,765,512       \$13,571,769       \$         2005 \$ -       -       (17,908,000)       165,640,000       16,326,000)       185,914,637       \$13,571,769       \$         2006 \$ -       -       (20,615,000)       155,640,000       19,261,500)       185,914,637       \$13,571,769       \$         2006 \$ -       -       (20,615,000)       155,640,000       19,261,500)       185,914,637       \$13,571,769       \$         2001       23,526,620)       51,135,994       \$       3,732,924       \$	19	2002 \$	1	8,749,000	(9,494,000)	230,831,000	(10,709,000)	229,424,000	\$ 16.747.95	<b>%</b>	27.456.95	
2004 5	20	2003 \$	•	•	(11,924,000)	218,907,000	(13,334,000)	218,552,512	\$ 15,954,33		29,288,33;	
2005 \$ (17,908,000) 185,55,000 (19,261,500) 185,914,637 \$13,571,769 \$ 2006 \$ (20,615,000) 155,640,000 155,650 147,600,278 5,3,732,924 5 3,475,477 5 2004 13,526,620 147,600,278 5,3,732,924 5 3,475,477 5 2004 13,526,620 147,600,278 5,3,732,924 5 3,475,477 5 2004 13,526,620 147,600,278 5,3,732,924 5 3,475,477 5 2004 13,526,620 147,600,278 5,3,732,924 5 3,475,477 5 2004 13,526,620 13,526,620 147,600,278 5,3,732,924 5 3,475,477 5 2004 13,526,620 13,526,620 137,029,418 5,2960,591 5 2,960,591 5 2,960,591 5 2,000 10-02 10,00	3	2004 \$	•	•	(14,744,000)	204, 163,000	(16,326,000)	203.765.512	\$ 14.874.88		31,200,882	~
2006 \$ - (20,615,000) 165,640,000 2001 2001 51,135,941 \$ 3,732,924 \$ 3,235,620) 31,135,941 \$ 3,732,924 \$ 3,2732,924 \$ 3,2732,924 \$ 3,2732,924 \$ 3,2732,924 \$ 3,2732,924 \$ 3,275,477 \$ 2003 (3,526,620) 47,609,278 \$ 3,2732,924 \$ 3,226,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,7029,418 \$ 3,732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2732,924 \$ \$ 3,2756,670 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,526,620 \$ 3,7029,418 \$ \$ 3,732,924 \$ \$ 3,732,926 \$ \$ 3,732,926 \$ \$ 3,732,926 \$ \$ 3,732,926 \$ \$ 3,732,926 \$ \$ 3,732	22	2005 \$	•	•	(17,908,000)	186,255,000	(19,261,500)	185,914,637	\$13,571,76		32,833,269	
BEP         54,662,518         54,662,518         53,732,924         53,732,924           2001         2002         51,135,898         (3,526,620)         47,609,278         5,3732,924           2003         (3,526,620)         47,609,278         (3,526,620)         47,609,278         5,375,924           2004         (3,526,620)         47,609,278         (3,526,620)         47,609,278         5,375,924           2005         (3,526,620)         47,609,278         (3,526,620)         47,609,278         5,375,924           2005         (3,526,620)         47,609,278         (3,526,620)         47,609,278         5,376,034           2005         (3,556,038         (3,526,620)         47,609,278         5,2960,591         2,960,591           2005         (3,526,620)         37,029,418         (1,002,658         5,296,593         2,960,591           2005         (3,556,038         (3,526,620)         37,029,418         (1,002,658         2,960,591           2006         (3,526,620)         37,029,418         (1,002,658         2,960,591         2,960,591           2006         (3,526,620)         37,029,418         (1,010,78         1,010,03         1,010,03           2006         (1,010,78         (1,010,78	53	2006 \$		۰	(20,615,000)	165,640,000	•		•			
BE7 2001 54,662,518 (3,526,620) 51,135,994 5 3,732,924 2002 23,526,620) 47,609,278 (3,526,620) 47,609,278 5 3,475,477 2003 2,526,620) 40,656,038 (3,526,620) 40,656,038 5 3,218,034 2005 2005 (3,526,620) 40,656,038 (3,526,620) 40,556,038 5 2,960,591 2005 2005 (3,526,620) 37,029,418 70 40,082,658 5 3,218,034 20,004 10,02 1,01-02 1,01-03 PCAM1 201 10,03 PCAM1 201 10,03 PCAM1 201 10,03 PCAM1 201 10,03 PCAM1 201 10,04 1,01-05 PCAM3 201 10,05 PCAM3 201 10,05 PCAM4	4											
2001 2002 2002 2003 2003 2004 2004 2004 2005 200 200		BEP										
2002 (3,526,620) 51,135,898 (3,526,620) 51,135,941 \$ 3,732,924 203 2003 (3,526,620) 47,609,278 (3,526,620) 47,609,278 5 3,475,477 2005 (3,526,620) 40,656,038 (3,526,620) 40,656,038 \$ 2,960,591 2005 (3,526,620) 37,029,418 (3,526,620) 40,556,038 \$ 2,960,591 2005 (3,526,620) 37,029,418 7 10 10 10 10 10 10 10 10 10 10 10 10 10	g	2001				54,662,518						
2003 (3,526,620) 47,609,278 (3,526,620) 47,609,278 5 3,475,477 2004 (3,526,620) 44,082,658 5 3,218,034 (3,526,620) 40,556,038 5 2,960,591 (3,526,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,020,418 (3,566,620) 37,020,418 (3,566,620) 37,020,418 (3,566,620) 37,020 (3,566,620) 37,020 (3,566,	27	2002			(3,526,620)	51, 135, 898	(3,526,620)	51, 135, 941			7.259.544	
2004 (3,526,620) 44,082,658 (3,526,620) 44,082,658 <b>5</b> 3,218,034 2005 (3,526,620) 37,029,418 (3,526,620) 40,556,038 <b>5</b> 2,960,591 9 2006 (3,526,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,029,418 (3,566,620) 37,020,418 (3,566,620) 37,020,418 (3,566,620) 37,020 (3,5	28	2003			(3,526,620)	47,609,278	(3,526,620)	47,609,278			7,002,097	
2005 (3,526,620) 40,556,038 (3,526,620) 40,556,038 <b>5</b> 2,960,591 2006 2006 (3,526,620) 37,029,418 <b>From</b> To Jul-02 Jun-03 PCA#1 Jul-02 Jun-04 PCA#2 Jul-04 PCA#2 Jul-05 PCA#3 Jul-05 PCA#4	60	2004			(3,526,620)	44,082,658	(3,526,620)	44,082,658			6,744,654	
2006 (3,526,620) 37,029,418 From To Jul-02 Jun-03 PCA#1 Jul-04 PCA#2 Jul-05 PCA#3 Jul-05 PCA#3 Jul-05 PCA#3	õ	2005			(3,526,620)	40,556,038	(3,526,620)	40,556,038			6,487,211	
From To Jul-02 Jun-03 PCA#1 Jul-04 Jun-05 PCA#3 Jul-05 PCA#3 Jul-05 PCA#3	Ξ	2006			(3,526,620)	37,029,418						
From     To       Jul-02     Jun-03       Jul-03     PCA#1       Jul-04     PCA#2       Jul-05     PCA#3       Jul-05     PCA#4	22					1						1
From To Jul-02 Jun-03 PCA#1 Jul-03 Jun-04 PCA#2 Jul-05 PCA#2 Jul-05 PCA#4	ñ									:		
Jul-02 Jun-03 PCA#1 5 Jul-03 Jun-04 PCA#2 5 Jul-05 PCA#3 5 Jun-06 PCA#4 5	ž						From	To		Ř	eturn + Amori	
Jul-03 Jun-04 PCA#2 5 Jul-04 Jun-05 PCA#3 5 Jul-05 Jun-06 PCA#4 5	ŝ						Jul-02	Jun-03	PCA#1	67	36,867,841	
Jul-04 Jun-05 PCA#3 \$ Jul-05 Jun-06 PCA#4 \$	စ္ဆ						Jul-03	Jun-04	PCA#2	\$	38,694,407	
Jul-05 Jun-06 PCA#4 \$	22						Jul-04	Jun-05	PCA#3	\$	40,597,120	
6	8						Jul-05	Jun-06	PCA#4	\$	42,236,653	
	<u>م</u>											

Exhibit D: Regulatory Assets

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Exhibit D

PCA Exhibits A-G v3.xls

# Exhibit No. \_\_\_(JHS-8) Page 26 of 30

Page 1 (

Exhibit E - Contract Adjustments

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Estimated costs from hypothetical PCA period

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						PCA Period				
			Limit - Rate or Total Cost ner	, notered	NI 10 0.11					Adjust for
Row	M	Note	UE-011570	MWh	MWh		Total Cost \$	Actual Rate	Change Change	Positive Differences
r.	CONTRACTS									
80		Exchange				A STATES STATES AND A STATES			a a fa she a a she a a a a	1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1
0		Rate Limit	\$ 67.00	21.432			<b>5 1 436 000</b>	<b>5</b> 67 00		
2	. '	Rate Limit	\$ 28.17	384,834			\$ 10 892 000	* 28.30		
=	•	Actual Cost						20.02 ¢		
5		Rate Limit	5135	92.170			5 4 733 MM	<ul> <li>K1 2K</li> </ul>		
13		NA		No. of Concession, Name						Sold and the second sec
4	Mid-Columbia	Actual Cost								
15		,						 		
16	•		\$ 29,382,000				000 257 92 5			350.000
17	•	Actual Cost								
18		Actual Cost								
<b>0</b>	•	Actual Cost								
8	•	Rate Limit	\$ 62.65	39,031			<b>\$</b> 2 500.000	<b>5</b> 64 05	5 1 20	47,000
		Actual Cost							CALCULAR DATE OF STREET	
21	•	through 12/31/02								
2	•	Exchange								
33	•	Rate Limit	\$ 30.04	1,731			\$ 52.000	<b>3</b> 0.04	· 5	
2		Rate Limit	\$ 74.87	32,692			\$ 2.448.000	\$ 74.88	<b>5</b> 0.01	480
32		NUG Rate Limit	<b>5</b> 61.01	436,000	436,000	•	\$ 26,639,600	\$ 61.10	5000	37 941
26	•	NUG Rate Limit	\$ 43.70	281,000	181,000	100,000	\$ 12,279,700	\$ 43.70	• ••	•
2	-	NUG Rate Limit	<b>5</b> 66.00	330,000	330,000	•	\$ 22,011,000	\$ 66.70	<b>\$</b> 0.70 <b>\$</b>	229.552
88	•	NUG Rate Limit	55.30	232,000	132,000	100,000	\$ 12,829,600	\$ 55.30	•••	•
20		Rate Limit	\$ 28.21	2,694			\$ 76,000	\$ 28.21	•••	•
3 5	UT FERC FUYAIIUP	Actual Cost								Sector Sector
3 8	OF Sumas Winter	NI IC Pate Limit	4.78 •	141,552			\$ 12,397,000	\$ 87.58	\$ 0.04	6,000
33	OF Sumas Summer	NI IC Pate Limit		000,000	000,500	-	\$ 54,631,200	<b>5</b> 82.40	<b>\$</b> 0.58	373,980
34	QF Sygitowicz	Rate Limit	5137		201,000	000'001	\$ 27,291,200	<b>5</b> 59.20	•••	•
35	OF Tenaska (excl. Reg. Amort.)	NUG Rate Limit	31.84	1 958 028	1 RCR 078			15.10 4		•
36	QF Twin Falls	Rate Limit	\$ 75.00	69.955	1,000,020	2000/2001	5 5 246 675			•
37	QF Weeks Falls	Rate Limit	\$ 75.00	12,542			\$ 940.650	5 75.00	s (000) s (000)	•
38	Skookumchuck	Actual Cost								
99						N-AMERICAN AVAILABLE A				
4	TOTAL								~	1.094.429
4									•	

<del>4</del> 4

Notes: 44

Exchange: No Adjustment. Either power for power exchage at zero cost or flood control for power at zero cost.

N/A: No Adjustment. Zero cost contracts. 4 <del>8</del>

Rate Limit: Calculate actual rate for PCA period, compare with contract rate assumed in revenue requirements; multiply rate change (if positive) times contract generation. Actual Cost: No Adjustment. Either no rate specified in contract, or rate based upon DJ market index, or as agreed. 44

Total Cost: Limit based upon total cost in rate year because contract escalation is in fixed demand charges.

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. <u>କୁ ସ୍</u>

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

Ethibit m

	Exhibit F - Colstrip	Availab	ilitv Adiustn	nent		
Row						
3	Part 1. Colstrip Equiva	alant Avai	lability during	DCA mented do t		
4		lient Avai	ability during	PCA period -12 r	viontn	
5		490	204			
6	PSE MW ->	<u>182</u> 307	<u>3&amp;4</u> 370			
7	Jul-02 <b>\</b>	85.00%	85.00%	PSE Wtd	days	
8	Aug 00	85.00%	85.00%	85.0%	31	
9	Aug-02 PSE: Sep-02 Enter date	1	85.00%	85.0%	31	
10	Oct-02 of 12	85.00%	85.00%	85.0%	30	
11	Nov-02 months	85.00%	85.00%	85.0%	31	
12	Dec-02 prior to en	<sup>d</sup> 85.00%	85.00%	85.0%	30	
13	Jan-03 Jof PCA	85.00%		85.0%	31	
14	Feb-03	85.00%	85.00%	85.0%	31	
15	Mar-03	85.00%	85.00%	85.0%	28	
16	Apr-03	85.00%	0.00%	38.5%	31	
17	May-03	85.00%	0.00% 0.00%	38.5%	30	
18	Jun-03	85.00%	0.00%	38.5%	31	
19		00.0070	0.0076	38.5%	30	
20	12 mo Average	85 000V				
21	Weighted by days in the mor	85.00%	56.59%	69.47%		
22	treighted by days in the mor	un		Weighted by PI	ant Capacity and days/month	ר
23						
24	Part 2 Calculate annu	at as all a h	1114			
25	Part 2. Calculate annu Less than 70%					
26	Actual Ratio		yes, penalty asse	ssed		
27	Target Ratio	69.47%				
28	Penalty	75.00%	per Collaborative	e agreement		
29	a chang	-5.53%				
30						
31	Penalty Ratio =	7.074				
32		-7.37%	= pen			
33			divide	d by 75.00% p	er Collaborative agreement	
34						
35	Part & Coloulate Annu		-			
36	Part 3. Calculate Annu	al Colstri	p Fixed Cost P	enalty		
37	Total Fixed Cost \$ 7	7 5 / / 000				
38	I otal Fixed Cost \$ 7	7,514,638	from Exhibit A-3	3 (Colstrip Total Reve	nue Requirement)	
39	Penalty Ratio =	-7.37%				
40		,712,733)				
•-		,1 14,100)	to Exhibit B lin	e 23		

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# 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	
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	- Actual data
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	<b>Jan-02</b>	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	Jui-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	Example data
29	Jan-03	85.00%	85.00%	31	Example data
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	
59	Jul-05				****
60	Aug-05			31	
61	Sep-05			31	
62	Oct-05			30	
63	Nov-05			31	
64	Dec-05			30	
65	Jan-06			31	
66	Feb-06			31	
67				28	
68	Mar-06			31	
69	Apr-06			30	
70	May-06			31	
10	Jun-06			30	

	Exhibit G - New Resc	ource Adi	Jstm	ent	
Row		<b>.</b>			
3	For New Resources with a Terr	ns Longer	than	2 Years	
4		0			
5	Name	Sample new	/ plant		
6	Description	Combined c	_		
7	• •	In-service d			
8	•				
9	-		_		
10	PCA Period	huby 2002	h		
11	i on i enou	July 2002 -	June 2	003	
13	Total Variable Component Actu	al			
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			•	00,700,000	
23	PCA Period Generation	(MWh)		750,000	
24		• •		,	
25	Actual Variable Cost	(\$/MWh)		\$45,000	
26	Compare with Baseline Rate			• • • • • • •	
27					
28	<b>Baseline Power Cost Rate</b>	(\$/MWh)		\$44.482	
29				-	
30	Lesser of Actual Cost or Base	eline Rate			
31	Baseline Power Cost Rate			\$44.482	
32					
33	Adjustment Needed?			Yes	
34	Adjustment needed if Baseline i	rate is lower th	an act	ual variable cost	
35					
36	Adjustment Rate	(\$/MWh)		-\$0.518	
37	Adjustment volume	(MWh)		750,000	
38	Adjustment Amount	(\$)	\$	(388,500) to Ex	chibit B line 24
			· ·		