CROSS-EXAMINATION EXHIBITS OF ICNU			
DeBoer, TAD-13CX	Tom A. DeBoer	PSE	PSE Response to ICNU DR 2.17
DeBoer, TAD-14CX	Tom A. DeBoer	PSE	PSE Response to ICNU DR 2.22
Cavanagh, RCC-8CX	Ralph C. Cavanagh	NWEC	NWEC Response to Staff DRs 9 and 11
Gaines, DEG-24CX	Don E. Gaines	PSE	Excerpt of FERC Financial Report
Gaines, DEG-25CX	Don E. Gaines	PSE	PSE Response to ICNU DR 10.2 (without attachment)
Mills, DEM-15CCX	David E. Mills	PSE	Confidential Sumas Price Comparison
Gould, WRG-9CX	Wayne R. Gould	PSE	ICNU Revision to PSE Exh. No. ___(WRG-5)
Gould, WRG-10CX	Wayne R. Gould	PSE	PSE Exh. No. ___(WRG-6)
Gould, WRG-11CX	Wayne R. Gould	PSE	Worksheet WRG-3 Summary Correction 2-8-2012
Story, JHS-33CX	John H. Story	PSE	Excerpt of 2010 BPA Annual Report
Story, JHS-34CX	John H. Story	PSE	Excerpt of REP-12-A-02

CROSS-EXAMINATION EXHIBITS OF ICNU – Tom A. DeBoer			
DeBoer, TAD-13CX	Tom A. DeBoer	PSE	PSE Response to ICNU DR 2.17
DeBoer, TAD-14CX	Tom A. DeBoer	PSE	PSE Response to ICNU DR 2.22

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-111048 and UG-111049
Puget Sound Energy, Inc.'s
2011 General Rate Case

ICNU DATA REQUEST NO. 02.17

ICNU DATA REQUEST NO. 02.17:

Is the CSA a "lost revenue adjustment mechanism" ("LRAM") as defined on pages 7-8 of Mr. De Boer's testimony? If not, please explain the differences between the CSA and the LRAM as Mr. De Boer describes that mechanism.

Response:

Puget Sound Energy, Inc.'s Conservation Savings Adjustment Rate could reasonably be characterized as a lost revenue adjustment mechanism, as described on pages 7-8 of the Prefiled Direct Testimony of Tom DeBoer, Exhibit No. ___(TAD-1T).

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-111048 and UG-111049
Puget Sound Energy, Inc.'s
2011 General Rate Case

ICNU DATA REQUEST NO. 02.22

ICNU DATA REQUEST NO. 02.22:

Consistent with the relationship stated on page 16, lines 6-8 of Mr. De Boer's testimony, does PSE believe that "plug load" identified by the Commission in ¶ 22, Report and Policy Statement in Docket No. U-100522, will provide use-per-customer increase? If so, would such use-per-customer increase result in a revenue-per-customer increase?

Response:

All other things being equal, the "plug load" identified by the Commission in paragraph 22 of its Report and Policy Statement in Docket No. U-100522 would place upward pressure on use-per-customer, and this would, all other things being equal, place upward pressure on revenue-per-customer. However, no conclusions can be drawn as to whether this plug load would in fact result in increased use-per-customer or revenue-per-customer, particularly in the presence of other factors, such as energy efficiency, which put downward pressure on use-per-customer and revenue-per customer.

CROSS-EXAMINATION EXHIBITS OF ICNU – Ralph C. Cavanagh			
Cavanagh, RCC-8CX	Ralph C. Cavanagh	NWEC	NWEC Response to Staff DRs 9 and 11

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-111048 and UG-111049
Puget Sound Energy, Inc.'s
2011 General Rate Case

COMMISSION STAFF'S DATA REQUEST NO. 9

COMMISSION STAFF'S DATA REQUEST NO. 9:

Please explain fully why a rate schedule that has "few members" and "accounts for a relatively small fraction of . . . projected revenues from energy charges", justifies excluding that rate schedule from a decoupling mechanism. See Exhibit No. __ (RCC-1T) at 13:12-15.

Response:

A rate schedule with few members would be subject to large annual fluctuations in per-customer fixed-cost revenue requirements as customers entered and departed, and if the rate schedule in question accounts for a relatively small fraction of the fixed cost revenue requirement that PSE recovers through its energy sales, excluding it from the decoupling mechanism will not have a material effect on PSE's incentive to pursue all cost-effective energy efficiency.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-111048 and UG-111049
Puget Sound Energy, Inc.'s
2011 General Rate Case

COMMISSION STAFF'S DATA REQUEST NO. 11

COMMISSION STAFF'S DATA REQUEST NO. 11:

Does Mr. Cavanagh believe excluding Schedules 40, 46 and 49, and 448, 449 and 459 from the decoupling mechanism is unduly discriminatory or is an undue preference? If so, please provide all facts and reasons supporting that belief. If not, please provide all facts and reasons supporting the opposite. This data request does not ask for a legal opinion, but rather Mr. Cavanagh's belief. If Mr. Cavanagh has no belief on the subject, please so indicate.

Response:

Beyond noting that it is not uncommon for decoupling mechanisms to exclude customers of this type, Mr. Cavanagh is not currently aware of any information that would add to his testimony. He does not believe that excluding these schedules is unduly discriminatory or an undue preference, for the reasons stated in his response to Request No. 9 above.

CROSS-EXAMINATION EXHIBITS OF ICNU – Don E. Gaines			
Gaines, DEG-24CX	**Don E. Gaines**	**PSE**	**Excerpt of FERC Financial Report**
Gaines, DEG-25CX	**Don E. Gaines**	**PSE**	**PSE Response to ICNU DR 10.2 (without attachment)**

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Puget Sound Energy, Inc. UBI#179010055	End of 2010/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	10,158,628,210	9,856,416,214
3	Construction Work in Progress (107)	200-201	628,385,944	358,732,272
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		10,787,014,154	10,215,148,486
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,703,041,987	3,626,534,836
6	Net Utility Plant (Enter Total of line 4 less 5)		7,083,972,167	6,588,613,650
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		7,083,972,167	6,588,613,650
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		8,057,045	7,529,405
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,213,318	3,250,232
19	(Less) Accum. Prov. for Depr. and Amort. (122)		863,648	521,760
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	49,380,155	52,614,832
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		68,718,285	70,185,375
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		8,232,813	4,605,177
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		129,680,923	130,133,856
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		13,672,281	11,028,751
36	Special Deposits (132-134)		4,736,379	19,027,623
37	Working Fund (135)		2,820,588	3,312,620
38	Temporary Cash Investments (136)		15,000,000	57,831,323
39	Notes Receivable (141)		3,461,113	4,011,914
40	Customer Accounts Receivable (142)		265,108,807	255,669,432
41	Other Accounts Receivable (143)		69,895,436	70,498,839
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		9,783,914	8,093,615
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		101,702	101,746
45	Fuel Stock (151)	227	16,316,797	13,909,264
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	79,805,285	60,820,277
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	4,416,676	3,784,171
55	Gas Stored Underground - Current (164.1)		75,272,703	81,241,450
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		632,728	662,698
57	Prepayments (165)		22,239,821	58,796,421
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	27
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		194,088,080	208,948,402
62	Miscellaneous Current and Accrued Assets (174)		5,924	0
63	Derivative Instrument Assets (175)		15,732,316	19,552,972
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		8,232,813	4,605,177
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		765,289,909	856,499,138
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		43,900,305	44,673,283
70	Extraordinary Property Losses (182.1)	230a	103,629,756	105,675,621
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	7,393,833	10,282,971
72	Other Regulatory Assets (182.3)	232	484,399,175	477,831,628
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,195,883	2,144,577
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		19,699	-46,589
78	Miscellaneous Deferred Debits (186)	233	364,954,870	275,337,264
79	Def. Losses from Disposition of Utility Plt. (187)		539,448	606,340
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		18,304,231	19,539,205
82	Accumulated Deferred Income Taxes (190)	234	549,148,984	359,027,388
83	Unrecovered Purchased Gas Costs (191)		5,991,769	-49,587,265
84	Total Deferred Debits (lines 69 through 83)		1,580,477,953	1,245,484,423
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		9,567,477,997	8,828,260,472

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	end of 2010/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	859,038	859,038
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		478,145,250	478,145,249
7	Other Paid-In Capital (208-211)	253	2,488,196,691	2,488,196,691
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	7,133,879	7,133,879
11	Retained Earnings (215, 215.1, 216)	118-119	167,604,344	358,392,112
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	4,882,711	-25,267,162
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-157,646,287	-210,120,354
16	Total Proprietary Capital (lines 2 through 15)		2,974,907,868	3,083,071,695
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	3,463,860,000	3,120,860,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		3,463,860,000	3,120,860,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		300,000	300,000
29	Accumulated Provision for Pensions and Benefits (228.3)		58,748,833	65,408,492
30	Accumulated Miscellaneous Operating Provisions (228.4)		75,678,611	49,479,811
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		155,178,787	89,717,386
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		25,416,838	24,095,388
35	Total Other Noncurrent Liabilities (lines 26 through 34)		315,323,069	229,001,077
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		247,000,000	105,000,000
38	Accounts Payable (232)		323,008,525	350,177,826
39	Notes Payable to Associated Companies (233)		22,597,785	22,897,785
40	Accounts Payable to Associated Companies (234)		616,351	0
41	Customer Deposits (235)		30,153,837	27,219,118
42	Taxes Accrued (236)	262-263	19,834,149	-22,181,657
43	Interest Accrued (237)		54,723,144	47,154,227
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	end of 2010/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		2,264,845	1,396,021
48	Miscellaneous Current and Accrued Liabilities (242)		17,573,377	17,161,655
49	Obligations Under Capital Leases-Current (243)		0	54,195,857
50	Derivative Instrument Liabilities (244)		398,232,217	227,247,311
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		155,178,787	89,717,386
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		960,825,443	740,550,757
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		94,479,314	98,536,108
57	Accumulated Deferred Investment Tax Credits (255)	266-267	115,553	320,118
58	Deferred Gains from Disposition of Utility Plant (256)		5,030,945	2,888,169
59	Other Deferred Credits (253)	269	150,729,165	195,277,866
60	Other Regulatory Liabilities (254)	278	98,077,992	38,716,128
61	Unamortized Gain on Reaquired Debt (257)		10,083	131,080
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,202,674,847	1,024,155,609
64	Accum. Deferred Income Taxes-Other (283)		301,443,718	294,751,865
65	Total Deferred Credits (lines 56 through 64)		1,852,561,617	1,654,776,943
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		9,567,477,997	8,828,260,472

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	PUGET WESTERN INC.	05/31/60		
2	Common			10,200
3	Retained Earnings			5,839,915
4	Add Paid in Capital			44,487,244
5	Subtotal			50,337,359
6				
7	HYDRO ENERGY DEVELOPMENT CORP	11/30/88		
8	Common			1,500
9	Retained Earnings			-31,107,076
10	Add Paid in Capital			33,383,049
11	Subtotal			2,277,473
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
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28				
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30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	52,614,832

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		10,200		2
	-957,204	4,882,711		3
		44,487,244		4
	-957,204	49,380,155		5
				6
				7
-1,500				8
30,413,020	694,056		1,100,000	9
-33,383,049				10
-2,971,529	694,056		1,100,000	11
				12
				13
				14
				15
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				34
				35
				36
				37
				38
				39
				40
				41
-2,971,529	-263,148	49,380,155	1,100,000	42

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
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(Expires 1/31/2012)

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FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

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Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Puget Sound Energy, Inc. UBI#179010055	**End of** 2010/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		350,015,648	371,642,349
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Preferred Stock Gain			338
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			338
10	License Hydro Project Excess Earnings			(63,974)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(63,974)
16	Balance Transferred from Income (Account 433 less Account 418.1)		26,358,208	161,508,008
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-186,732,954	(183,071,073)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-186,732,954	(183,071,073)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-30,413,027	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		159,227,875	350,015,648
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		8,376,461	8,376,461
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		8,376,461	8,376,461
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		167,604,336	358,392,109
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-25,267,162	(23,010,728)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-263,154	(2,256,434)
51	(Less) Dividends Received (Debit)			
52	Transfer HEDC Retained Earnings to PSE Retained Earnings		30,413,027	
53	Balance-End of Year (Total lines 49 thru 52)		4,882,711	(25,267,162)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

These financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than that under generally accepted accounting principles. As a result, the presentation of these financial statements differs from those presented using generally accepted accounting principles. Certain disclosures which are required by generally accepted accounting principles and not required by FERC have been excluded from these financial statements.

As required by FERC, Puget Sound Energy, Inc. (PSE) classifies certain items in its Form 1 Balance Sheet (primarily the classification of the components of accumulated deferred income taxes, non-legal asset retirement obligations, certain miscellaneous current and accrued liabilities, maturities of long-term debt, deferred debits and deferred credits) in a manner different than that required by generally accepted accounting principles.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

PSE is a public utility incorporated in the state of Washington that furnishes electric and gas services in a territory covering 6,000 square miles, primarily in the Puget Sound region. The results of PSE's subsidiaries are presented on an equity basis, except for PSE Funding, Inc., a PSE subsidiary, which is presented on a consolidated basis. The consolidated financial statements are presented after elimination of all significant intercompany items and transactions. Certain amounts previously reported have been reclassified to conform with current year presentations with no effect on total equity or net income.

PSE Funding, Inc., was a wholly-owned, bankruptcy remote subsidiary of PSE, formed for the purpose of purchasing customers' accounts receivable, both billed and unbilled. PSE Funding was dissolved in 2009. PSE Funding, Inc. used the customers' accounts receivable as collateral to borrow short-term debt at lower interest rates than could be obtained by PSE. The cash received from the short-term debt was provided to PSE to assist with its working capital needs.

Utility Plant

PSE capitalizes, at original cost, additions to utility plant, including renewals and betterments. Costs include indirect costs such as engineering, supervision, certain taxes, pension and other employee benefits and an Allowance For Funds Used During Construction (AFUDC). Replacements of minor items of property and major maintenance are included in maintenance expense. When utility plant is retired and removed from service, the original cost of the property is charged to accumulated depreciation; costs associated with removal of the property, less salvage, are charged to the cost of removal regulatory liability.

Non-Utility Property, Plant and Equipment

The costs of other property, plant and equipment are stated at historical cost. Expenditures for refurbishment and improvements that significantly add to productive capacity or extend useful life of an asset are capitalized. Replacement of minor items is expensed on a current basis. Gains and losses on assets sold or retired are reflected in earnings.

Depreciation and Amortization

For financial statement purposes, the Company provides for depreciation and amortization on a straight-line basis. Amortization is recorded for intangibles such as regulatory assets and liabilities, computer software and franchises. The depreciation of automobiles, trucks, power-operated equipment, tools and office equipment is allocated to asset and expense accounts based on usage. The annual depreciation provision stated as a percent of a depreciable electric utility plant was 2.7% and 2.6% in 2010 and 2009; depreciable gas utility plant was 3.6% in 2010 and 2009; and depreciable common utility plant was 11.8% and 9.6% in 2010 and 2009. Depreciation on other property, plant and equipment is calculated primarily on a straight-line basis over the useful lives of the assets. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

Cash and Cash Equivalents

Cash and cash equivalents consist of demand bank deposits and short-term highly liquid investments with original maturities of three months or less at the time of purchase. Cash equivalents are reported at cost, which approximates fair value, and were $15.9 and $38.2 million as of December 31, 2010 and 2009, respectively.

Restricted Cash

Restricted cash represents cash to be used for specific purposes. The restricted cash balance was $5.5 million and $19.8 million at December 31, 2010 and 2009, respectively. Restricted cash in 2010 and 2009 of $0.7 million, and $0.8 million, respectively, represents funds held by Puget Western, Inc., a PSE subsidiary, for a real estate development project. As of December 31, 2010, other restricted cash includes $3.2 in a Benefit Protection Trust and $1.6 million in other restricted cash accounts.

Materials and Supplies

Materials and supplies are used primarily in the operation and maintenance of electric and natural gas distribution and transmission systems as well as spare parts for combustion turbines used for the generation of electricity. PSE records these items at weighted-average cost.

Fuel and Gas Inventory

Fuel and gas inventory is used in the generation of electricity and for future sales to the Company's natural gas customers. Fuel inventory consists of coal, diesel and natural gas used for generation. Gas inventory consists of natural gas and liquefied natural gas (LNG) held in storage for future sales. PSE records these items at the lower of cost or market value using the weighted-average cost method.

Regulatory Assets and Liabilities

PSE accounts for its regulated operations in accordance with ASC 980 "Regulated Operations" (ASC 980). ASC 980 requires PSE to defer certain costs that would otherwise be charged to expense, if it were probable that future rates will permit recovery of such costs. It similarly requires deferral of revenues or gains and losses that are expected to be returned to customers in the future. Accounting under ASC 980 is appropriate as long as rates are established by, or subject to, approval by independent third-party regulators, rates are designed to recover the specific enterprise's cost of service, and, in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. In most cases, PSE classifies regulatory assets and liabilities as long-term assets or liabilities. The exception is the Purchased Gas Adjustment (PGA) which is a current asset.

Below is a chart with the allowed return on the net regulatory assets and liabilities and times periods associated.

Period	Rate of Return	After-Tax Return
April 8, 2010 - present	8.10%	6.90%
November 1, 2008 - April 7, 2010	8.25	7.00

Allowance for Funds Used During Construction

The AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. The amount of AFUDC recorded in each accounting period varies depending principally upon the level of construction work in progress and the AFUDC rate used. AFUDC is capitalized as a part of the cost of utility plant and is credited to interest expense and as a non-cash item to other income. Cash inflow related to AFUDC does not occur until these charges are reflected in rates.

The AFUDC rates authorized by the Washington Utilities and Transportation Commission (Washington Commission) for natural gas and electric utility plant additions based on the effective dates are as follows:

Effective Date	Washington Commission AFUDC Rates
April 8, 2010 - present	8.10%
November 1, 2008 - April 7, 2010	8.25

The Washington Commission authorized the Company to calculate AFUDC using its allowed rate of return. To the extent amounts calculated using this rate exceed the AFUDC calculated rate using the Federal Energy Regulatory Commission (FERC) formula, PSE capitalizes the excess as a deferred asset, crediting other income. The deferred asset is being amortized over the average useful life of PSE's non-project electric utility plant which is approximately 30 years.

The following table presents the AFUDC amounts:

	Year Ended December 31,	
(Dollars in Thousands)	2010	2009
Equity AFUDC	$ 12,677	$ 4,177
Washington Commission AFUDC	3,715	10,693
Total in other income	16,392	14,870
Debt AFUDC	14,157	9,214
Total AFUDC	30,549	24,084

Revenue Recognition

Operating utility revenue is recognized when services are rendered, and includes estimated unbilled revenue. Sales to other utilities are recognized in accordance with ASC 605 "Revenue Recognition" (ASC 605). Non-utility subsidiaries recognize revenue when services are performed or upon the sale of assets. Revenue from retail sales is billed based at tariff rates approved by the Washington Commission. Sales of RECs are deferred as a regulatory liability.

PSE collected Washington state excise taxes (which are a component of general retail rates) and municipal taxes totaling $231.1 million and $247.8 million for 2010 and 2009. The Company's policy is to report such taxes on a gross basis in operating revenue and taxes other than income taxes in the accompanying consolidated statements of income.

Allowance for Doubtful Accounts

Allowance for doubtful accounts are provided for electric and natural gas customer accounts based upon a historical experience rate of write-offs of energy accounts receivable as compared to operating revenue. The allowance account is adjusted monthly for this experience rate. Other non-energy receivable balances are reserved in the allowance account based on facts and circumstances surrounding the receivable including, among other things, collection trends, prevailing and anticipated economic conditions and specific customer credit risk, indicating some or all of the balance is uncollectible. The allowance account is maintained until either receipt of payment or the likelihood of collection is considered remote at which time the allowance account and corresponding receivable balance are written off.

The Company's allowance for doubtful accounts at December 31, 2010 and 2009 was $9.8 million and $8.1 million, respectively.

Self-Insurance

PSE currently has no insurance coverage for storm damage and recent environmental contamination occurring on PSE-owned property. PSE is self-insured for a portion of the risk associated with comprehensive liability, workers' compensation claims and catastrophic property losses other than those which are storm related. The Washington Commission has approved the deferral of certain uninsured storm damage costs that exceed $7.0 million for the years ending 2006 through 2008 and $8.0 million for subsequent years of qualifying storm damage costs for collection in future rates if the outage meets the Institute of Electrical and Electronics Engineers (IEEE) outage criteria for system average interruption duration index.

Federal Income Taxes

For presentation in PSE's financial statements, income taxes are allocated to the subsidiaries on the basis of separate company computations of tax, modified by allocating certain consolidated group limitations which are attributed to the separate company. Taxes payable or receivable are settled with Puget Holdings.

PSE provides for deferred taxes on certain assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes, as required by ASC 740 "Income Taxes" (ASC 740). Uncertain tax positions are also accounted for under ASC 740. The Company reports the associated interest in interest expense and income tax penalties in other expense in the accompanying consolidated statements of income.

Rate Adjustment Mechanisms

PSE has a PCA mechanism that provides for a rate adjustment process if PSE's costs to provide customers' electricity varies from a baseline power cost rate established in a rate proceeding. All significant variable power supply cost drivers are included in the PCA mechanism (hydroelectric generation variability, market price variability for purchased power and surplus power sales, natural gas and coal fuel price variability, generation unit forced outage risk and wheeling cost variability). The PCA mechanism apportions increases or decreases in power costs, on a graduated scale, between PSE and its customers. Any unrealized gains and losses from derivative instruments accounted for under ASC 815, "Derivatives and Hedging" (ASC 815), are deferred in proportion to the cost-sharing arrangement under the PCA mechanism. On January 10, 2007, the Washington Commission approved the PCA mechanism with the same annual graduated scale but without a cap on excess power costs.

The graduated scale is as follows:

Annual Power Cost Variability	Customers' Share	Company's Share
+/- $20 million	0%	100%
+/- $20 million - $40 million	50%	50%
+/- $40 million - $120 million	90%	10%
+/- $120 + million	95%	5%

For the year ended December 31, 2010, the annual power costs variability was between $20.0 million and $40.0 million. Accordingly, PSE and the customer share the costs in excess of $20.0 million in equal proportion.

The differences between the actual cost of PSE's natural gas supplies and natural gas transportation contracts and costs currently allowed by the Washington Commission are deferred and recovered or repaid through the PGA mechanism. The PGA mechanism allows PSE to recover expected gas costs, and defer, as a receivable or liability, any gas costs, including interest, that exceed or fall short of this expected gas cost amount in the PGA mechanism rates.

Natural Gas Off-System Sales and Capacity Release

PSE contracts for firm natural gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for natural gas by its firm customers. Due to the variability in weather, winter peaking consumption of natural gas by most of its customers and other factors, PSE holds contractual rights to natural gas supplies and transportation and storage capacity in excess of its average annual requirements to serve firm customers on its distribution system. For much of the year, there is excess capacity available for third-party natural gas sales, exchanges and capacity releases. PSE sells excess natural gas supplies, enters into natural gas supply exchanges with third parties outside of its distribution area and releases to third parties excess interstate natural gas pipeline capacity and natural gas storage rights on a short-term basis to mitigate the costs of firm transportation and storage capacity for its core natural gas customers. The proceeds from such activities, net of transactional costs, are accounted for as reductions in the cost of purchased natural gas and passed on to customers through the PGA mechanism, with no direct impact on net income. As a result, PSE nets the sales revenue and associated cost of sales for these transactions in purchased natural gas.

Non-Core Gas Sales

As part of the Company's electric operations, PSE provides natural gas to an electric supplier and to its gas-fired generation facilities. The projected volume of natural gas for power is relative to the price of natural gas. Based on the market prices for natural gas, PSE may use the gas it has already purchased to generate power or PSE may sell the already purchased natural gas. The net proceeds from such activities are accounted for in other electric operating revenue and are included in the PCA mechanism.

Production Tax Credit

Production Tax Credits (PTCs) represent federal income tax incentives available to companies that generate energy from qualifying renewable sources. Prior to July 1, 2010, PTCs that were generated were passed-through to customers in retail sales. After July 1, 2010, PTCs which are generated and owed to customers are recorded as a regulatory liability with a corresponding reduction in electric operating revenue until PSE utilizes the tax credit on its tax return, at which time the PTCs will be credited to customers in retail sales.

Accounting for Derivatives

ASC 815 requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value unless the contracts qualify for an exception. PSE enters into derivative contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts and swaps. The majority of PSE's physical contracts qualify for the Normal Purchase Normal Sale (NPNS) exception to derivative accounting rules. PSE may enter into financial fixed contracts to economically hedge the variability of certain index-based contracts. Those contracts that do not meet the NPNS exception are marked-to-market to current earnings in the statements of income, subject to deferral under ASC 980, for energy related derivatives due to the PCA mechanism and PGA mechanism.

On July 1, 2009, PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying its financial reporting. The contracts that were de-designated were physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market adjustments are recognized through earnings. The amount previously recorded in accumulated other comprehensive income (OCI) for derivatives accounted for as hedges were transferred to earnings in the same period or periods during which the hedged transaction affected earnings or sooner if management determines that the forecasted transaction is probable of not occurring. As a result, the Company will continue to experience the earnings impact of these reversals from OCI in future periods.

The Company may enter into swap instruments or other financial derivative instruments to manage the interest rate risk associated with its long-term debt financing and debt instruments.

Fair Value Measurements of Derivatives

ASC 820, "Fair Value Measurements and Disclosures" (ASC 820), defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). However, as permitted under ASC 820, the Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities measured and reported at fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements as it believes that the approach is used by market participants for these types of assets and liabilities. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The Company values derivative instruments based on daily quoted prices from an independent external pricing service. When external quoted market prices are not available for derivative contracts, the Company uses a valuation model that uses volatility assumptions relating to future energy prices based on specific energy markets and utilizes externally available forward market price curves. All derivative instruments are sensitive to market price fluctuations that can occur on a daily basis.

Stock-Based Compensation

The Company applies the fair value approach to stock compensation and estimates fair value in accordance with provisions of ASC 718, "Compensation – Stock Compensation." Effective February 6, 2009, as a result of the merger, all outstanding shares of the Company were accelerated and vested, the stock compensation plan was terminated and there was no stock-based compensation. The Company recognized $14.5 million of stock compensation expense which was recorded in merger and related costs.

Debt Related Costs

Debt premiums, discounts, expenses and amounts received or incurred to settle hedges are amortized over the life of the related debt for the Company. The premiums and costs associated with reacquired debt are deferred and amortized over the life of the related new issuance, in accordance with ratemaking treatment for PSE.

Statements of Cash Flows

The following non-cash investing and financing activities have occurred at the Company:

- PSE did not incur any capital lease obligations for the year ended December 31, 2010. PSE incurred capital lease obligations of $15.9 million for vehicles for the year ended December 31, 2009. PSE incurred $45.8 million for energy generation turbines for the year ended December 31, 2008.

Accumulated Other Comprehensive Income (Loss)

The following tables set forth the components of the Company's accumulated other comprehensive income (loss) at December 31:

Puget Sound Energy	At December 31,	
(Dollars in Thousands)	2010	2009
Net unrealized loss on energy derivatives	$ (34,612)	$ (83,158)
Settlement of cash flow hedge contracts	(7,257)	(7,574)
Net unrealized loss and prior service cost on pension plans	(115,778)	(119,388)
Total PSE, net of tax	$ (157,647)	$ (210,120)

(2) New Accounting Pronouncements

Recently Adopted Accounting Pronouncements

Business Combinations. On January 1, 2009, PSE adopted ASC 805, "Business Combinations." The objective of the standard is to improve the relevance, representational faithfulness and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. To accomplish that, the standard establishes principles and requirements for how the acquirer: (1) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree; (2) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

Fair Value Measurements and Disclosures. In January 2010, the FASB issued Accounting Standards Update (ASU) 2010-6, "Improving Disclosures About Fair Value Measurements" (ASU 2010-6), which requires new disclosures about recurring or nonrecurring fair value measurements including significant transfers into and out of Level 1 and Level 2 fair value measurements and information on purchases, sales, issuances, and settlements on a gross basis in the reconciliation of Level 2 fair value measurements. ASU 2010-6 was effective for annual reporting periods beginning after December 15, 2009, except for the Level 3 reconciliation disclosures, which were effective for annual periods beginning after December 15, 2010. As these new requirements relate solely to disclosures, the adoption of this guidance did not impact the Company's consolidated financial statements.

In September 2009, the FASB issued ASU 2009-12, "Fair Value Measurements and Disclosures: Investments in Certain Entities that Calculate Net Asset Value per Share (or its equivalent)." The standard allows the reporting entity, as a practical expedient, to measure the fair value of investments that do not have readily determinable fair values on the basis of the net asset value per share of the investment if the net asset value of the investment is calculated in a matter consistent with Topic 946, "Financial Services – Investment Companies." The standard requires disclosures about the nature and risk of the investments and whether the investments are probable of being sold at amounts different from the net asset value per share. The Company adopted the standard as of December 31, 2009, and such adoption did not have an impact on the consolidated financial statements. For additional information, see Note 14.

On January 1, 2008, the Company adopted ASC 820 for all financial assets and liabilities and nonfinancial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The standard defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. This standard does not require any new fair value measurements, but provides guidance on how to measure fair value by providing a fair value hierarchy used to classify the source of the information.

The Company adopted ASC 820 on January 1, 2008, prospectively, for financial and nonfinancial instruments measured on a recurring basis, with certain exceptions, including the initial impact of changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under ASC 815. The difference between the carrying amounts and the fair values of those instruments originally recorded under guidance in ASC 815 was recognized as a cumulative-effect adjustment to the opening balance of retained earnings of $9.0 million before tax as a result of recording a deferred loss on net derivative assets and liabilities.

In January 2009, the Company adopted ASC 820 for all nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. The application of the fair value measurement guidance to nonrecurring nonfinancial assets and nonrecurring nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis did not impact the Company's consolidated financial statements.

Accounting Standards Codification. In June 2009, FASB issued ASU 2009-01, Topic 105, "GAAP amendments based on the Statement of Financial Standards No. 168 – The FASB Accounting Standards Codification and the Hierarchy of GAAP." With this ASU, the FASB Codification became the authoritative source of GAAP. The FASB Codification was effective for interim and annual reporting periods ending after September 15, 2009, which was September 30, 2009 for the Company. The FASB Codification did not have a material impact on the financial reporting of the Company.

Derivative Instruments Disclosures. In January 2009, FASB issued a new standard, which required additional disclosures about the Company's objectives in using derivative instruments and hedging activities, and tabular disclosures of the effects of such instruments and related hedged items on the Company's financial position, financial performance, and cash flows. For additional information, see Note 11.

Retirement Benefits Disclosures. Effective December 31, 2009, ASC 715 "Compensation – Retirement Benefits" (ASC 715) directs companies to provide additional disclosures about plan assets of a defined benefit pension or other postretirement plan. The objectives of the disclosures are to disclose the following: (1) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; (2) major categories of plan assets; (3) inputs and valuation techniques used to measure the fair value of plan assets; (4) effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and (5) significant concentrations of risk within plan assets. For additional information, see Note 14.

Subsequent Events. In May 2009, FASB issued ASC 855, "Subsequent Events," a new standard on subsequent events. The standard does not require significant changes regarding recognition or disclosure of subsequent events but does require disclosure of the date through which subsequent events have been evaluated for disclosure and recognition. The standard is effective for financial statements issued after June 15, 2009, which was the quarter ended June 30, 2009 for the Company. The implementation of this standard did not have a significant impact on the financial statements of the Company.

(3) Regulation and Rates

Electric Regulation and Rates

Storm Damage Deferral Accounting

The Washington Commission issued a general rate case order that defined deferrable catastrophic/extraordinary losses and provided that costs in excess of $8.0 million annually may be deferred for qualifying storm damage costs that meet the IEEE outage criteria for system average interruption duration index. PSE's storm accounting, which allows deferral of certain storm damage costs. In 2010 and 2009, PSE incurred $23.5 million and $4.7 million, respectively, in storm-related electric transmission and distribution system restoration costs, of which $14.0 million was deferred in 2010 and none in 2009.

Electric General Rate Case

On April 2, 2010, the Washington Commission issued its order in PSE's consolidated electric rate case filed in May 2009 which approved a general rate increase for electric customers of 3.7% annually, or $74.1 million, effective April 8, 2010. In its order, the Washington Commission approved a weighted cost of capital of 8.1% and a capital structure that included 46.0% common equity with an after-tax return on equity of 10.1%.

Power Cost Only Rate Case

Power Cost Only Rate Case (PCORC), a limited-scope proceeding, was approved in 2002 by the Washington Commission to periodically reset power cost rates. In addition to providing the opportunity to reset all power costs, the PCORC proceeding also provides for timely review of new resource acquisition costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission approved an expedited six-month PCORC decision timeline rather than the statutory 11-month timeline for a general rate case.

Accounting Orders and Petitions

On May 21, 2008, PSE filed an accounting petition for a Washington Commission order that authorizes the deferral of a settlement payment of $10.7 million incurred as a result of the recent settlement of a lawsuit in the state of Montana over alleged damages caused by the operation of the Colstrip Montana coal-fired steam electric generation facility (Colstrip). The payment was expensed pending resolution of the accounting petition. In the April 2, 2010 general rate case order, the Washington Commission allowed recovery of $8.4 million in PSE's operating costs, which represents the amount of the settlement, net of insurance proceeds.

On November 5, 2008, PSE filed an accounting petition for a Washington Commission order authorizing the deferral and recovery of interest due the Internal Revenue Service (IRS) for tax years 2001 to 2006 along with carrying costs incurred in connection with the interest due. In October 2005, the Washington Commission issued an order authorizing the deferral and recovery of costs associated with increased borrowings necessary to remit deferred taxes to the IRS. In the April 2, 2010 general rate case order, the Washington Commission denied recovery of the interest due to the IRS. PSE expensed the interest deferral of $6.9 million in April 2010.

On November 6, 2008, PSE filed an accounting petition for a Washington Commission order authorizing accounting treatment and amortization related to payments received for taking assignment of Westcoast Pipeline Capacity. The accounting petition seeks deferred accounting treatment and amortization of the regulatory liability to power costs beginning in November 2009 and extending over the remaining primary term of the pipeline capacity contract through October 31, 2018. In the April 2, 2010 general rate case order, the Washington Commission approved the deferral of $7.5 million and amortization as proposed.

On December 30, 2008, the Washington Commission approved an order authorizing the sale of Puget Energy and PSE to Puget Holdings subject to a Settlement Stipulation which included 78 conditions. Items included in the conditions that may affect the financial statements are dividend restrictions for Puget Energy and PSE which are discussed in Note 4. In addition, the conditions provided for rate credits of $10.0 million per year (less certain merger savings) over a ten-year period beginning at the closing of the transaction.

On April 17, 2009, the Washington Commission issued an order approving and adopting a settlement agreement that authorized PSE to defer certain ownership and operating costs related to its purchase of the Mint Farm Electric Generating Station (Mint Farm) that were incurred prior to PSE recovering such costs in electric customer rates. Under Washington state law, a jurisdictional electric utility may defer the costs associated with purchasing and operating a natural gas plant that complies with the greenhouse gas (GHG) emissions performance standard until the plant is included in rates or for two years from the date of purchase, whichever occurs sooner. In the April 2, 2010 general rate case order, the Washington Commission approved the prudence of the Mint Farm acquisition and recovery of the deferred costs from the plant's in-service date to the date of the order. The deferred costs are to be amortized over 15 years. As of December 31, 2010, the balance of the regulatory asset, net of amortization was $28.3 million.

On March 13, 2009, PSE filed with the Washington Commission an application for authority to sell and transfer certain assets related to the Company's White River Hydroelectric Project (the Project) to the Cascade Water Alliance (CWA). PSE also requested in its application that the Washington Commission waive applicable provisions of the Revised Code of Washington and Washington Administrative Code with regard to certain surplus property related to the Project, which PSE expects to sell in the near future but which is not part of the CWA transaction. On May 14, 2009, the application for authority to transfer certain assets to CWA was approved by the Washington Commission and the application for waiver with regard to the Surplus Property was denied and requires PSE to seek approval prior to the sale of any property.

On September 30, 2009, PSE filed an accounting petition requesting that the Washington Commission authorize PSE to normalize over 10 years a Treasury grant of $28.7 million received under Section 1603 of the American Recovery and Reinvestment Act of 2009 associated with the Wild Horse expansion project. Treasury grants are tax free grants related to certain renewable energy infrastructure that are available in lieu of the PTC allowed under the Internal Revenue Code. The Washington Commission issued an order approving the accounting petition on December 10, 2009.

On October 16, 2009, PSE filed an accounting petition requesting that the Washington Commission authorize the deferral and recovery of incremental costs associated with protecting the Company's infrastructure, facilitating public safety, and preparing PSE's electric and natural gas system in the Green River Valley flood plain in anticipation of release of water from the United States Army Corps of Engineers' (Corps) Howard Hanson Dam (Dam). In the event of actual flooding, PSE also petitioned the Washington Commission to allow the deferral of costs associated with the repair and restoration of any electric and gas system infrastructure affected by a flood.

Name of Respondent	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.		04/15/2011	2010/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

On January 28, 2010, the Washington Commission approved PSE's request for authorization to defer the costs associated with restoring the Company's infrastructure, facilitating public safety, and repairing the Company's electric and natural gas system in the Green River Valley flood plain in the event evacuation is required or flooding occurs due to operations associated with the Dam. This authorization is conditioned on PSE incurring incremental operation and maintenance costs in excess of $5.0 million per year associated with repair or restoration of the Company's systems around the Green River. The Washington Commission's order will be effective until the date the Corps confirms that the Dam has been permanently repaired and that Corps' operations will return to normal.

The Washington Commission issued an order in 2010 relating to how REC proceeds should be handled for regulatory accounting and ratemaking purposes. The order required REC proceeds to be recorded as regulatory liabilities and that amounts recorded would accrue interest at a rate to be determined in a later filing. In its petition, PSE had sought approval for the use of $21.1 million of REC proceeds to be used as an offset against its California wholesale energy sales regulatory asset. In response to the order, PSE adjusted the carrying value of its regulatory asset in the second quarter of 2010 by $17.8 million (from $21.1 million to $3.3 million), with the $3.3 million then offset against the Company's RECs regulatory liability. The Company's California wholesale energy sales regulatory asset represented unpaid bills for power sold into the markets maintained by the California Independent System Operator during the 2000-2001 California Energy Crisis, the claims of which were settled along with all counterclaims against PSE in a settlement agreement approved by the FERC on July 1, 2009.

On May 20, 2010, PSE filed an accounting petition requesting that the Washington Commission approve: (1) the creation of a regulatory asset account for the prepayments made to the Bonneville Power Administration (BPA) associated with network upgrades to the Central Ferry substation related to the Lower Snake River wind project; (2) the monthly accrual of carrying charges on that regulatory asset at PSE's approved net of tax rate of return; and (3) the ability to provide customers the BPA interest received through a reduction to transmission expense. The petition is still pending approval by the Washington Commission.

Production Tax Credit / Renewable Energy Credit

PSE has a tariff which passes the benefits of the PTCs to customers. The tariff is not subject to the sharing bands in the PCA. Prior to July 1, 2010, PSE could adjust the PTC tariff annually based on differences between the PTC credits provided to the customers and the PTC credits actually earned, plus estimated PTC credits for the following year, less interest associated with the deferred tax balance for the PTC credits. Since customers received the benefit of the tax credits as they were generated and the Company did not receive a credit from the IRS until the tax credits were utilized, the Company will be reimbursed for its carrying costs. PSE will continue to be reimbursed for carrying costs through December 31, 2011 when the credits that were provided and not used will be received from customers.

Effective July 1, 2010, the Washington Commission approved a change in PSE's PTC tariff as PSE has not been able to utilize PTCs since 2007, due to insufficient taxable income caused primarily by bonus tax depreciation. The Washington Commission approved PSE suspending its PTC tariff, effective July 1, 2010. This resulted in an overall increase in PSE's electric rates of 1.7%, however, this will not result in an increase in earnings.

On September 22, 2010, a joint proposal and accounting petition was filed with the Washington Commission by PSE, Washington Commission Staff and Industrial Customers of Northwest Utilities which addressed how to recover PTCs provided to customers that have not been utilized and addresses REC proceeds to be returned to customers. On October 26, 2010, the Washington Commission issued an order granting the joint proposal and accounting petition. The order allows the Company to credit customers for REC revenue received and deferred through November 2009. This credit will reduce rates by $27.7 million, or 2.5%, over five months beginning November 2010 through March 2011. RECs received after November 2009 will be retained by PSE and will be used to recapture the benefit of PTCs previously provided to customers. Once these PTCs are utilized by PSE on its tax return, the customers will receive the benefit.

Treasury Grant

Section 1603 of the American Recovery and Reinvestment Tax Act of 2009 (Section 1603) authorizes the United States Department of the Treasury (U.S. Treasury) to make grants to corporations who place specified energy property in service provided certain conditions are met. The Wild Horse expansion facility was placed into service on November 9, 2009. The Wild Horse facility was expanded from 229 megawatts (MW) to 273 MW through the addition of wind turbines. On December 22, 2009, PSE filed an application with the U.S. Treasury to request a grant on the expansion in the amount of $28.7 million. Section 1603 precludes a recipient from claiming PTCs on property for which a grant is claimed. On February 19, 2010, the U.S. Treasury approved the grant and payment was received in February 2010.

On December 30, 2010, the Washington Commission approved revisions to PSE's PTC tariff, effective January 1, 2011, which changed the methodology by which PTCs are passed-through to customers. Due to the uncertainty of realizing the benefit of PTCs, the PTCs will pass-through to customers following the year in which they are able to be utilized on PSE's tax return, rather than in the same year in which they are generated by qualifying wind powered facilities. The rate schedule will pass-through $5.5 million of the $28.7 million treasury grant in 2011. The order authorized PSE to pass back one-tenth of the treasury grant on an annual basis and includes 23 months of treasury grant amortization to customers from February 2010 through December 2011, which represents the month the treasury grant funds were received through the end of the period over which the rates will be set. This represents an overall average rate reduction of 0.3%, with no impact to net income. Since the tariff now addresses additional federal incentives, it has been renamed the Federal Incentive Tracker.

PCA Mechanism

In 2002, the Washington Commission approved a PCA mechanism that provides for a rate adjustment process if PSE's costs to provide customers' electricity varies from a baseline power cost rate established in a rate proceeding. On January 10, 2007, the Washington Commission approved the continuation of the PCA mechanism under the same annual graduated scale but without a cap on excess power costs. All significant variable power supply cost variables (hydroelectric and wind generation, market price for purchased power and surplus power, natural gas and coal fuel price, generation unit forced outage risk and transmission cost) are included in the PCA mechanism.

The PCA mechanism apportions increases or decreases in power costs, on a calendar year basis, between PSE and its customers on a graduated scale. For a discussion of the accounting policy and PCA graduated scale, see Note 1.

Gas Regulation and Rates

Gas General Rate Case

On March 14, 2011, the Washington Commission issued its order, effective April 1, 2011, in PSE's natural gas general rate case filed in October 2010. In its order, the Washington Commission approved the $19.0 million or 1.8% settlement that the parties had agreed to in the proceeding.

On April 2, 2010, the Washington Commission issued its order, effective April 8, 2010, in PSE's natural gas general rate case filed in May 2009, approving a general rate increase of 0.8% annually or $10.1 million. In its order, the Washington Commission approved a weighted cost of capital of 8.1% and a capital structure that included 46.0% common equity with an after-tax return on equity of 10.1%.

Purchased Gas Adjustment

PSE has a PGA mechanism in retail natural gas rates to recover variations in natural gas supply and transportation costs. Variations in natural gas rates are passed through to customers; therefore, PSE's net income is not affected by such variations.

The following table sets for PGA rate adjustments that were approved by the Washington Commission and the corresponding impact to PSE's annual revenue based on the effective dates:

Effective Date	Percentage Increase (Decrease) in Rates	Annual Increase (Decrease) in Revenue (Dollars in Millions)
November 1, 2010	1.9%	$ 18.3
October 1, 2009 – October 31, 2010	(17.1)	(198.1)
June 1, 2009 – May 31, 2010	(1.8)	(21.2)
October 1, 2008 – September 30, 2009	11.1	108.8

(4) Dividend Payment Restrictions

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's electric and natural gas mortgage indentures. At December 31, 2010, approximately $416.7 million of unrestricted retained earnings was available for the payment of dividends under the most restrictive mortgage indenture covenant.

Beginning February 6, 2009, pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE's common equity ratio, calculated on a regulatory basis, is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. Also, pursuant to the merger order, PSE may not declare or make any distribution unless on the date of distribution PSE's corporate credit/issuer rating is investment grade, or, if its credit ratings are below investment grade, PSE's ratio of Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA) to interest expense for the most recently ended four fiscal quarter periods prior to such date is equal to or greater than three to one. The common equity ratio, calculated on a regulatory basis, was 46.5% at December 31, 2010 and the EBITDA to interest expense was 3.9 to one.

PSE's ability to pay dividends is also limited by the terms of its credit facilities pursuant to which, PSE is not permitted to pay dividends during any Event of Default, or if the payment of dividends would result in an Event of Default (as defined in the facilities), such as failure to comply with certain financial covenants.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
	(1) X An Original	(Mo, Da, Yr)	
Puget Sound Energy, Inc.	(2) _ A Resubmission	04/15/2011	2010/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

At December 31, 2010, the Company was in compliance with all applicable covenants, including those pertaining to the payment of dividends.

(5) Utility Plant

Utility Plant (Dollars In Thousands)	Estimated Useful Life (Years)	At December 31 2010	At December 31 2009
Electric, gas and common utility plant classified by prescribed accounts at original cost:			
Distribution plant	10-50	$ 6,054,961	$ 5,759,617
Production plant	25-125	2,585,864	2,385,228
Transmission plant	45-65	463,546	403,657
General plant	5-35	449,980	363,739
Intangible plant (including capitalized software)	3-50	184,706	343,180
Plant acquisition adjustment	NA	223,108	251,693
Underground storage	25-60	40,558	40,052
Liquefied natural gas storage	25-45	14,310	14,310
Plant held for future use	NA	54,098	38,532
Other	NA	8,057	7,529
Plant not classified	NA	58,822	201,013
Capital leases	1-2	--	55,396
Less: accumulated provision for depreciation		(3,509,277)	(3,453,165)
Subtotal		$ 6,628,733	$ 6,410,781
Construction work in progress	NA	628,387	358,732
Net utility plant		$ 7,257,120	$ 6,769,513

Jointly owned generating plant service costs are included in utility plant service cost. The following table indicates the Company's percentage ownership and the extent of the Company's investment in jointly owned generating plants in service at December 31, 2010. These amounts are also included in the Utility Plant table above.

Jointly Owned Generating Plants (Dollars in Thousands)	Energy Source (Fuel)	Company's Ownership Share	Plant in Service at Cost	Accumulated Depreciation
Colstrip Units 1 & 2	Coal	50%	$ 263,467	$ (149,764)
Colstrip Units 3 & 4	Coal	25%	496,485	(298,176)
Colstrip Units 1 – 4 Common Facilities [1]	Coal	various	252	(175)
Frederickson 1	Gas	49.85%	70,701	(6,374)

1 *The Company's ownership is 50% for Colstrip Units 1 & 2 and 25% for Colstrip Units 3 & 4.*

There were no valuation adjustments to asset retirement obligations (ARO) in conjunction with the merger in 2009. The Company did not recognize any new AROs in 2010 or in 2009.

The following table describes all changes to the Company's ARO liability:

	At December 31	
(Dollars in Thousands)	2010	2009
Asset retirement obligation at beginning of period	$ 24,095	$ 29,661
New asset retirement obligation recognized in the period	--	--
Liability settled in the period	(2,341)	(3,621)
Revisions in estimated cash flows	2,413	(3,483)
Accretion expense	1,249	1,538
Asset retirement obligation at end of period	$ 25,416	$ 24,095

The Company has identified the following obligations which were not recognized at December 31, 2010:

- a legal obligation under Federal Dangerous Waste Regulations to dispose of asbestos-containing material in facilities that are not scheduled for remodeling, demolition or sales. The disposal cost related to these facilities could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated currently;
- an obligation under Washington state law to decommission the wells at the Jackson Prairie natural gas storage facility upon termination of the project. Since the project is expected to continue as long as the Northwest pipeline continues to operate, the liability cannot be reasonably estimated currently;
- an obligation to pay its share of decommissioning costs at the end of the functional life of the major transmission lines. The major transmission lines are expected to be used indefinitely; therefore, the liability cannot be reasonably estimated currently;
- a legal obligation under Washington state environmental laws to remove and properly dispose of certain under and above ground fuel storage tanks. The disposal costs related to under and above ground storage tanks could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated currently;

(6) Long-Term Debt

Puget Sound Energy

(Dollars in Thousands)

First Mortgage Bonds, Pollution Control Bonds , Senior Notes and Junior Subordinated Notes

		At December 31				At December 31	
Series	Due	2010	2009	Series	Due	2010	2009
7.120%	2010	$ --	$ 7,000	7.200%	2025	$ 2,000	$ 2,000
7.960%	2010	--	225,000	7.020%	2027	300,000	300,000
7.690%	2011	260,000	260,000	7.000%	2029	100,000	100,000
6.830%	2013	3,000	3,000	5.000%[1]	2031	138,460	138,460
6.900%	2013	10,000	10,000	5.100%[1]	2031	23,400	23,400
5.197%	2015	150,000	150,000	5.483%	2035	250,000	250,000
7.350%	2015	10,000	10,000	6.724%	2036	250,000	250,000
7.360%	2015	2,000	2,000	6.274%	2037	300,000	300,000
6.750%	2016	250,000	250,000	5.757%	2039	350,000	350,000
6.740%	2018	200,000	200,000	5.764%	2040	250,000	--
9.570%	2020	25,000	25,000	5.795%	2040	325,000	--
7.150%	2025	15,000	15,000	6.974%[2]	2067	250,000	250,000
Total PSE long-term debt						$ 3,463,860	$ 3,120,860

1 *Pollution Control Bonds*

2 *Junior Subordinated Notes*

Puget Sound Energy Long-Term Debt

PSE has in effect a shelf registration statement under which it may issue, from time to time, senior notes secured by first mortgage bonds. The Company remains subject to the restrictions of PSE's indentures and credit agreements on the amount of first mortgage bonds that PSE may issue.

On March 25, 2011, PSE issued $300.0 million of senior notes secured by first mortgage bonds. The notes have a term of 30 years and an interest rate of 5.638%. Net proceeds from the note offering were used to repay short-term indebtedness outstanding under PSE's capital expenditure credit facility, which debt was incurred to fund utility capital expenditures and replenish cash that had been used to repay $260 million of medium-term notes with a 7.69% interest rate that matured on February 1, 2011.

On June 29, 2010, PSE issued $250.0 million of senior notes secured by first mortgage bonds. The notes have a term of 30 years and an interest rate of 5.764%. Net proceeds from the note offering were used to repay $7.0 million of medium-term notes with a 7.12% interest rate that matured on September 13, 2010 and to repay short-term debt outstanding under the $400.0 million capital expenditure credit facility.

On March 8, 2010, PSE issued $325.0 million of senior notes secured by first mortgage bonds. The notes have a term of 30 years and an interest rate of 5.795%. Net proceeds from the offering were used to replenish funds utilized to repay $225.0 million of senior medium-term notes which matured on February 22, 2010 and carried a 7.96% interest rate. Remaining net proceeds were used to pay down debt under PSE's capital expenditure credit facility.

Substantially all utility properties owned by PSE are subject to the lien of the Company's electric and natural gas mortgage indentures. To issue additional first mortgage bonds under these indentures, PSE's earnings available for interest must exceed certain minimums as defined in the indentures. At December 31, 2010, the earnings available for interest exceeded the required amount.

Puget Sound Energy Pollution Control Bonds

PSE has two series of Pollution Control Bonds outstanding. Amounts outstanding were borrowed from the City of Forsyth, Montana who obtained the funds from the sale of Customized Pollution Control Refunding Bonds issued to finance pollution control facilities at Colstrip Units 3 & 4.

Each series of bonds is collateralized by a pledge of PSE's first mortgage bonds, the terms of which match those of the Pollution Control Bonds. No payment is due with respect to the related series of first mortgage bonds so long as payment is made on the Pollution Control Bonds.

Long-Term Debt Maturities

The principal amounts of long-term debt maturities for the next five years and thereafter are as follows:

(Dollars in Thousands)	2011	2012	2013	2014	2015	Thereafter	Total
Maturities of:							
PSE long-term debt	$ 260,000	$ --	$ 13,000	$ --	$ 162,000	$ 3,028,860	$ 3,463,860

Financial Covenants

The Company's credit facilities contain financial covenants related to cash flow interest coverage, cash flow to net debt outstanding and debt service coverage, each as specified in the facilities. As of December 31, 2010, the Company is in compliance with its long-term debt financial covenants.

(7) Redeemable Securities

On February 5, 2009, PSE deposited with its Redemption and Paying Agent approximately $1.9 million to defease the preferred stock and issued an irrevocable notice that the shares were to be redeemed on March 13, 2009. The Redemption and Paying Agent paid shareholders their redemption price plus accrued dividends through March 13, 2009. As of December 31, 2010, there were no outstanding shares of preferred stock or other redeemable securities.

(8) Estimated Fair Value of Financial Instruments

Puget Sound Energy

The following table presents the carrying amounts and estimated fair value of PSE's financial instruments at December 31, 2010 and 2009:

	December 31, 2010		December 31, 2009	
(Dollars in Thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets:				
Cash and cash equivalents	$ 31,603	$ 31,603	$ 72,172	$ 72,172
Restricted cash	4,737	4,737	19,028	19,028
Notes receivable and other	72,419	72,419	74,063	74,063
Electric derivatives	9,762	9,762	5,140	5,140
Gas derivatives	5,971	5,971	14,413	14,413
Financial liabilities:				
Short-term debt	$ 247,000	$ 247,000	$ 105,000	$ 105,000
Short-term debt owed by PSE to Puget Energy	22,598	22,598	22,898	22,898
Junior subordinated notes	250,000	246,864	250,000	232,684
Current maturities of long-term debt (fixed-rate)	260,000	261,472	232,000	234,632
Non-current maturities of long-term debt (fixed-rate)	2,953,860	3,267,994	2,638,860	2,815,048
Electric derivatives	242,581	242,581	145,690	145,690

Gas derivatives	155,651	155,651	81,557	81,557

The fair value of long-term notes and variable rate notes were estimated using U.S. Treasury yields and related current market credit spreads, interpolating to the maturity date of each issue.

The carrying values of short-term debt and notes receivable are considered to be a reasonable estimate of fair value. The carrying amount of cash, which includes temporary investments with original maturities of three months or less, is also considered to be a reasonable estimate of fair value.

(9) Liquidity Facilities and Other Financing Arrangements

As of December 31, 2010 and 2009, PSE had $247.0 million and $105.0 million in short-term debt outstanding, respectively, exclusive of the demand promissory note with Puget Energy. PSE's weighted-average interest rate on short-term debt, including borrowing rate, commitment fees and the amortization of debt issuance costs, during 2010 and 2009 was 5.11% and 3.59%, respectively. As of December 31, 2010, PSE had several committed credit facilities that are described below

Puget Sound Energy Credit Facilities

PSE maintains three committed unsecured revolving credit facilities that provide, in the aggregate, $1.15 billion in short-term borrowing capability and which mature concurrently in February 2014. These facilities consist of a $400.0 million credit agreement for working capital needs, a $400.0 million credit facility for funding capital expenditures and a $350.0 million facility to support energy hedging activities.

PSE's credit agreements contain usual and customary affirmative and negative covenants that, among other things, place limitations on PSE's ability to incur additional indebtedness and liens, issue equity, pay dividends, transact with affiliates and make asset dispositions and investments. The credit agreements also contain financial covenants which include a cash flow interest coverage ratio and, in addition, if PSE has a below investment grade credit rating, a cash flow to net debt outstanding ratio (each as specified in the facilities). PSE certifies its compliance with these covenants to participating banks each quarter. As of December 31, 2010, PSE was in compliance with all applicable covenants.

These credit facilities contain similar terms and conditions and are syndicated among numerous committed lenders. The agreements provide PSE with the ability to borrow at different interest rate options and include variable fee levels. The credit agreements allow PSE to borrow at the bank's prime rate or to make floating rate advances at the London Interbank Offered Rate (LIBOR) plus a spread that is based upon PSE's credit rating. The $400.0 million working capital facility and $350.0 million credit agreement to support energy hedging allow for issuing standby letters of credit. PSE must also pay a commitment fee on the unused portion of the credit facilities. The spreads and the commitment fee depend on PSE's credit ratings. As of the date of this report, the spread to the LIBOR is 0.85% and the commitment fee is 0.26%. The $400.0 million working capital facility also serves as a backstop for PSE's commercial paper program.

In May 2010, PSE's credit facilities were amended, in part, to include a swing line feature allowing same day availability on such borrowings up to $50.0 million. This feature does not increase the total lending commitments.

As of December 31, 2010, $247.0 million was drawn and outstanding under PSE's $400.0 million capital expenditure facility in addition to a $12.6 million letter of credit supporting the BPA contracts. No loans were outstanding under PSE's working capital facility and no loans or letters of credit were outstanding under PSE's $350.0 million facility supporting energy hedging activities. Outside of the credit agreements, PSE had a $5.7 million letter of credit in support of a long-term transmission contract.

Demand Promissory Note. On June 1, 2006, PSE entered into a revolving credit facility with Puget Energy in the form of a Demand Promissory Note (Note) pursuant to which PSE may borrow up to $30.0 million from Puget Energy subject to approval by

Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lowest of the weighted-average interest rate of PSE's outstanding commercial paper interest rate or PSE's senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. At December 31, 2010 and 2009, the outstanding balance of the Note was $22.6 million and $22.9 million, respectively, and the interest rate was 1.1% and 1.2%, respectively.

(10) Leases

PSE leases buildings and assets under operating leases. In January 2009, PSE entered into an agreement to purchase the Fredonia combustion turbines for $42.4 million and its fleet vehicles for $11.8 million, which purchase was completed in January 2010. These were previously leased under an operating lease. Entering into the purchase agreement resulted in the reclassification of the Fredonia and fleet leases as capital leases. Certain leases contain purchase options and renewal and escalation provisions. Rent expense net of sublease receipts were:

(Dollars in Thousands) At December 31	
2010	$ 22,493
2009	31,747

Payments received for the subleases of properties was approximately $0.1 million for each of the years ended 2010, 2009 and 2008.

Future minimum lease payments for non-cancelable leases net of sublease receipts are:

(Dollars in Thousands) At December 31	Operating
2011	$ 11,870
2012	13,288
2013	13,559
2014	12,412
2015	12,479
Thereafter	71,330
Total minimum lease payments	$134,938

PSE leased a portion of its owned natural gas transmission pipeline infrastructure under a non-cancelable operating lease to a third party which expired in 2009.

(11) Accounting for Derivative Instruments and Hedging Activities

PSE employs various portfolio optimization strategies, but is not in the business of assuming risk for the purpose of realizing speculative trading revenue. The nature of serving regulated electric customers with its portfolio of owned and contracted electric generation resources exposes PSE and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. Therefore, wholesale market transactions are focused on balancing PSE's energy portfolio, reducing costs and risks where feasible and reducing volatility in costs and margins in the portfolio. PSE's energy risk portfolio management function monitors and manages these risks using analytical models and tools. In order to manage risks effectively, PSE enters into physical and financial transactions which are appropriate for the service territory of PSE and are relevant to its regulated electric and natural gas portfolios.

On July 1, 2009, PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying its financial reporting. The contracts that were de-designated related to physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market adjustments are recognized through earnings. The amount previously recorded in accumulated OCI is transferred to earnings in the same period or periods during which the hedged transaction affected earnings or sooner if management determines that the forecasted transaction is probable of not occurring. As a result, the Company will continue to experience the earnings impact of these reversals from OCI in future periods.

The Company manages its interest rate risk through the issuance of mostly fixed-rate debt of various maturities. The Company utilizes internal cash from operations, commercial paper, and credit facilities to meet short-term funding needs. Short-term obligations are commonly refinanced with fixed-rate bonds or notes when needed and when interest rates are considered favorable. The Company may enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts. As of December 31, 2010, PSE did not have any outstanding interest rate swap instruments.

The following table presents the fair value and locations of PSE's derivative instruments recorded on the balance sheet at December 31, 2010 and 2009:

Derivatives Not Designated as Hedging Instruments

Puget Sound Energy	December 31, 2010		December 31, 2009	
(Dollars in Thousands)	Assets [1]	Liabilities [1]	Assets [1]	Liabilities [1]
Electric portfolio:				
Current	$ 4,716	$ 142,780	$ 4,137	$ 75,323
Long-term	5,046	99,801	1,003	70,367
Gas portfolio: [2]				
Current	2,784	100,273	10,811	62,207
Long-term	3,187	55,378	3,602	19,350
Total derivatives	$ 15,733	$ 398,232	$ 19,553	$ 227,247

1 *Balance sheet location: Unrealized (gain) loss on derivative instruments.*

2 *PSE had a derivative liability and an offsetting regulatory asset of $149.7 million at December 31, 2010 and $67.1 million at December 31, 2009 related to financial contracts used to economically hedge the cost of physical gas purchased to serve natural gas customers. All fair value adjustments on derivatives relating to the natural gas business have been reclassified to a deferred account in accordance with ASC 980 due to the PGA mechanism. All increases and decreases in the cost of natural gas supply are passed on to customers with the PGA mechanism and the gains and losses on the hedges in future periods will be recorded as gas costs.*

For further details regarding the fair value of derivative instruments and their Level categorization, see Note 12.

The following table presents the net unrealized (gain) loss of PSE's derivative instruments recorded on the statements of income for the years ended December 31, 2010 and 2009:

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2010	2009
Gas for power generation	$ 91,666	$ (2,835)
Power exchange	(2,620)	(2,822)
Power	77,907	4,321
Credit reserve [1]	--	82
Total net unrealized (gain) loss on derivative instruments	$ 166,953	$ (1,254)

1 *Beginning in the second quarter 2009, the credit reserve was incorporated as a component of the individual derivative value and not recorded separately.*

The following table presents the effect of hedging instruments on PSE's OCI and statements of income for the years ended December 31, 2010 and 2009:

Puget Sound Energy
(Dollars in Thousands)

Year Ended December 31,								
Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives [1] (Effective Portion [2])		Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion [3])			Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion and Amount Excluded from Effectiveness Testing [3])		
	2010	2009	Location	2010	2009	Location	2010	2009
Interest rate contracts:	$ --	$ --	Interest expense	$ (488)	$ (488)		$ --	$ --
Commodity contracts:	575	(49,848)	Electric generation fuel	(56,594)	(117,524)	Net unrealized gain on derivative instruments	--	--
Electric derivatives	--	(11,429)	Purchased electricity	(17,207)	(20,686)	Net unrealized loss on derivative instruments	--	(2,749)
Total	$ 575	$ (61,277)		$ (74,289)	$(138,698)		$ --	$ (2,749)

1 *On July 1, 2009 all electric and gas related cash flow hedge relationships were de-designated. Subsequent measurements of fair value are recorded through earnings, not OCI.*
2 *Changes in OCI are reported in after-tax dollars.*
3 *A reclassification of a loss in OCI increases accumulated OCI and decreases earnings. Amounts reported are in pre-tax dollars.*

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivatives representing hedge ineffectiveness are recognized in current earnings. PSE expects that $33.4 million of losses in OCI will be reclassified into earnings within the next twelve months. The maximum length of time over which PSE is hedging its exposure to the variability in future cash flows extends to February 2015 for purchased electricity contracts and to October 2015 for gas for power generation contracts.

The following table presents the effect of PSE's derivatives not designated as hedging instruments on income during the years ended December 31, 2010 and 2009:

Puget Sound Energy
(Dollars in Thousands)

	Location	Year Ended December 31, 2010	2009
Commodity contracts:			
Electric derivatives	Net unrealized gain (loss) on derivative instruments	$ (166,953)	$ 4,003 [1]
	Electric generation fuel	(100,514)	(89,255)
	Purchased electricity	(36,886)	(40,770)
Total gain (loss) recognized in income on derivatives		$ (304,353)	$ (126,022)

1 *Differs from the amount stated in the statements of income as it does not include $(2.7) million related to hedge ineffectiveness.*

The Company had the following outstanding contracts as of December 31, 2010:

Puget Sound Energy at December 31, 2010	Number of Units
Derivatives not designated as hedging instruments:	
Gas derivatives [1]	372,984,645 MMBtus
Electric generation fuel	104,055,000 MMBtus
Purchased electricity	9,630,725 MWhs

1 *Unrealized gains (losses) on gas derivatives are offset by a regulatory asset or liability in accordance with ASC 980 due to the PGA mechanism.*

The Company is exposed to credit risk primarily through buying and selling electricity and natural gas to serve its customers. Credit risk is the potential loss resulting from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for, among other things, counterparty credit analysis, exposure measurement, exposure monitoring, and exposure mitigation.

The Company monitors counterparties that have significant swings in credit default swap rates, have credit rating changes by external rating agencies, have changes in ownership or are experiencing financial problems. Where deemed appropriate, the Company may request collateral or other security from its counterparties to mitigate potential credit default losses. Criteria employed in this decision include, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure.

It is possible that volatility in energy commodity prices could cause the Company to have material credit risk exposure with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. However, as of December 31, 2010, approximately 99.9% of the Company's energy portfolio exposure, excluding NPNS transactions, is with counterparties that are rated at least investment grade by the major rating agencies and 0.1% are either rated below investment grade or not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated.

The Company generally enters into the following master agreements: (1) WSPP, Inc. (WSPP) agreements – standardized power sales contract in the electric industry; (2) International Swaps and Derivatives Association (ISDA) agreements – standardized financial gas and electric contracts; and (3) North American Energy Standards Board (NAESB) agreements – standardized physical gas contracts. The Company believes that such agreements reduce credit risk exposure because such agreements provide for the netting and offset of monthly payments and, in the event of counterparty default, termination payments.

The Company computes credit reserves at a master agreement level by counterparty (i.e., WSPP, ISDA, or NAESB). The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads, in determination of reserves. The Company recognizes that external ratings may not always reflect how a market participant perceives a counterparty's risk of default. The Company uses both default factors published by Standard & Poor's and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted average default tenor for that counterparty's deals. The default tenor is used by weighting the fair value and contract tenors for all deals for each counterparty and coming up with an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. Moreover, the Company applies its own default factor to compute credit reserves for counterparties that are in a net liability position. Credit reserves are booked as contra accounts to unrealized gain (loss) positions. As of December 31, 2010, the Company was in a net liability position with the majority of counterparties, so the default factors of counterparties did not have a significant impact on reserves for the year. The majority of the Company's derivative contracts are with financial institutions and other utilities operating within the Western Electricity Coordinating Council. Despite its net liability position, PSE was not required to post any additional collateral with any of its counterparties. Additionally, PSE did not trigger any collateral requirements with any of its counterparties nor were any of PSE's counterparties required to post additional collateral resulting from credit rating downgrades.

As of December 31, 2010, the Company did not have any outstanding energy supply contracts with counterparties that contained credit risk related contingent features, which could result in a counterparty requesting immediate payment or demanding immediate and ongoing full overnight collateralization on derivative instruments in a net liability position.

The table below presents the fair value of the overall contractual contingent liability positions for the Company's derivative activity at December 31, 2010:

Puget Sound Energy

Contingent Feature (Dollars in Thousands)	Fair Value [1] Liability	Posted Collateral	Contingent Collateral
Credit rating [2]	$ (45,422)	$ --	$ 45,422
Requested credit for adequate assurance	(125,759)	--	--
Forward value of contract [3]	(17,585)	--	--
Total	$ (188,766)	$ --	$ 45,422

1 *Represents the derivative fair value of contracts with contingent features for counterparties in net derivative liability positions at December 31, 2010. Excludes NPNS, accounts payable and accounts receivable liability.*

2 *Failure by PSE to maintain an investment grade credit rating from each of the major credit rating's agencies provides counterparties a contractual right to demand collateral.*

3 *Collateral requirements may vary, based on changes in forward value of underlying transactions relative to contractually defined collateral thresholds.*

(12) Fair Value Measurements

ASC 820 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy defined by ASC 820 are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities. Equity securities that are also classified as cash equivalents are considered Level 1 if there are unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and options.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. At each balance sheet date, the Company performs an analysis of all instruments subject to ASC 820 and includes in Level 3 all of those instruments whose fair value is based on significant unobservable inputs.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. If a fair value measurement relies on inputs from different levels of the hierarchy, the entire measurement must be placed based on the lowest level input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. On a daily basis, the Company obtains quoted forward prices for the electric and natural gas market from an independent external pricing service. Those forward price quotes are then used in addition to other various inputs to determine the reported fair value. Some of the inputs include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), assumptions for time value and also the impact of the Company's nonperformance risk on its liabilities.

As of December 31, 2010, the Company considered the markets for its electric and natural gas Level 2 derivative instruments to be actively traded. Management's assessment is based on the trading activity volume in real-time and forward electric and natural gas markets. The Company regularly confirms the validity of pricing service quoted prices (e.g. Level 2 in the fair value hierarchy) used to value commodity contracts to the actual prices of commodity contracts entered into during the most recent quarter.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) X An Original (2) _ A Resubmission	04/15/2011	2010/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

The following tables set forth, by level within the fair value hierarchy, the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis and the reconciliation of the changes in the fair value of derivatives classified as Level 3 in the fair value hierarchy as of December 31, 2010 and 2009:

Puget Sound Energy	Fair Value measurement At December 31, 2010				Fair Value Measurement At December 31, 2009			
(Dollars in Thousands)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Electric derivative instruments	$ --	$ 1,874	$ 7,888	$ 9,762	$ --	$ 2,469	$ 2,671	$ 5,140
Gas derivative instruments	--	1,487	4,484	5,971	--	14,298	115	14,413
Cash equivalents	15,184	--	--	15,184	37,370	--	--	37,370
Restricted cash	3,246	--	--	3,246	3,305	--	--	3,305
Total assets	$ 18,430	$ 3,361	$ 12,372	$ 34,163	$ 40,675	$ 16,767	$ 2,786	$ 60,228
Liabilities:								
Electric derivative instruments	$ --	$ 147,257	$ 95,324	$ 242,581	$ --	$ 46,690	$ 99,000	$ 145,690
Gas derivative instruments	--	147,308	8,343	155,651	--	77,438	4,119	81,557
Total liabilities	$ --	$ 294,565	$ 103,667	$ 398,232	$ --	$ 124,128	$ 103,119	$ 227,247

Puget Sound Energy Level 3 Roll-Forward Net (Liability)	Year Ended December 31,	
(Dollars in Thousands)	2010	2009
Balance at beginning of period	$ (100,333)	$ (132,256)
Changes during period:		
Realized and unrealized energy derivatives		
- included in earnings	(112,180)	(776)
- included in other comprehensive income	--	(38,047)
- included in regulatory assets/liabilities	(2,665)	(7,824)
Purchases, issuances, and settlements	29,832	28,779
Transferred into Level 3 [1]	225	(6,778)
Transferred out of Level 3 [1]	93,826	56,569
Balance at end of period	$ (91,295)	$ (100,333)

1 *The energy derivatives transferred in/out of Level 3 in 2009 includes the cash equivalents of $1.4 million. These cash equivalents became Level 2 during the second quarter 2009.*

Realized gains and losses on energy derivatives for Level 3 recurring items are included in energy costs in the Company's consolidated statements of income under purchased electricity, electric generation fuel or purchased natural gas when settled.

Unrealized gains and losses on energy derivatives for Level 3 recurring items are included in the net unrealized (gain) loss on derivative instruments section in the Company's consolidated statements of income. The Company does not believe that the fair value diverges materially from the amounts the Company currently anticipates realizing on settlement or maturity.

Certain energy derivative instruments are classified as Level 3 in the fair value hierarchy because Level 3 inputs are significant to their fair value measurement. Energy derivatives transferred out of Level 3 represent existing assets or liabilities that were classified as Level 3 at the start of the reporting period for which the lowest significant input became observable during the current reporting period and were transferred into Level 2. Conversely, energy derivatives transferred into Level 3 from Level 2 represent scenarios in which the lowest significant input became unobservable during the current reporting period. The Company had no transfers between Level 2 and Level 1 during the year ended December 31, 2010 or 2009.

(13) Employee Investment Plans

The Company has a qualified Employee Investment Plan under which employee salary deferrals and after-tax contributions are used to purchase several different investment fund options. PSE's contributions to the Employee Investment Plan were $11.8 million, $11.4 million and $10.0 million for the years 2010, 2009 and 2008, respectively. The Employee Investment Plan eligibility requirements are set forth in the plan documents.

(14) Retirement Benefits

PSE has a defined benefit pension plan covering substantially all PSE employees. Pension benefits earned are a function of age, salary and years of service. PSE also maintains a non-qualified Supplemental Executive Retirement Plan (SERP) for its key senior management employees. In addition to providing pension benefits, PSE provides certain health care and life insurance benefits for retired employees. These benefits are provided principally through an insurance company. The insurance premiums are based on the benefits provided during the year, and are paid primarily by retirees.

The following tables summarize PSE's change in benefit obligation, change in plan assets, net periodic benefit cost and other changes in OCI for the years ended December 31, 2010 and 2009:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2010	2009	2010	2009	2010	2009
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 504,786	$ 460,586	$ 39,152	$ 39,348	$ 15,953	$ 18,088
Service cost	16,089	14,141	1,024	1,068	106	125
Interest cost	27,975	27,734	2,165	2,315	880	960
Amendment	(21,866)	--	--	--	--	--
Actuarial loss (gain)	32,163	25,094	3,663	707	867	(1,296)
Benefits paid	(26,532)	(22,769)	(1,682)	(4,286)	(2,030)	(2,342)
Medicare part D subsidiary received	--	--	--	--	803	418
Benefit obligation at end of period	$ 532,615	$ 504,786	$ 44,322	$ 39,152	$ 16,579	$ 15,953
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 485,689	$ 392,900	$ --	$ --	$ 8,790	$ 8,435
Actual return on plan assets	55,312	97,158	--	--	1,140	1,952
Employer contribution	12,000	18,400	1,682	4,286	388	745
Benefits paid	(26,532)	(22,769)	(1,682)	(4,286)	(2,030)	(2,342)
Fair value of plan assets at end of period	$ 526,469	$ 485,689	$ --	$ --	$ 8,288	$ 8,790
Funded status at end of period	$ (6,146)	$(19,097)	$(44,322)	$(39,152)	$ (8,291)	$ (7,163)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) X An Original (2) _ A Resubmission	04/15/2011	2010/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2010	2009	2010	2009	2010	2009
Amounts recognized in Statement of Financial Position consist of:						
Current liabilities	$ --	$ --	$ (3,506)	$ (2,978)	$ (44)	$ (39)
Noncurrent liabilities	(6,146)	(19,097)	(40,816)	(36,174)	(8,247)	(7,124)
Total	$ (6,146)	$(19,907)	$(44,322)	$(39,152)	$ (8,291)	$ (7,163)
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss (gain)	$ 187,240	$ 173,822	$ 11,770	$ 8,876	$ (4,492)	$ (5,281)
Prior service cost	(17,245)	5,170	867	1,430	134	267
Transition obligations	--	--	--	--	100	150
Total	$ 169,995	$ 178,992	$ 12,637	$ 10,306	$ (4,258)	$ (4,864)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2010	2009	2010	2009	2010	2009
Components of net periodic benefit cost:						
Service cost	$ 16,089	$ 14,141	$ 1,024	$ 1,068	$ 106	$ 125
Interest cost	27,975	27,734	2,165	2,315	880	960
Expected return on plan assets	(43,892)	(43,453)	--	--	(509)	(455)
Amortization of prior service cost	548	1,134	562	616	132	83
Amortization of net loss (gain)	7,325	3,702	769	886	(553)	(460)
Amortization of transition obligation	--	--	--	--	50	50
Net periodic benefit cost (income)	$ 8,045	$ 3,258	$ 4,520	$ 4,885	$ 106	$ 303

Puget Sound Energy	Qualified Pension Benefit		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2010	2009	2010	2009	2010	2009
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						
Net loss (gain)	$ 20,743	$(28,610)	$ 3,663	$ 707	$ 236	$(2,794)
Amortization of net loss (gain)	(7,325)	(3,702)	(769)	(886)	553	461
Prior service cost (credit)	(21,867)	--	--	--	--	--
Amortization of prior service cost	(546)	(1,134)	(562)	(616)	(132)	(83)
Amortization of transition (asset) obligation	--	--	--	--	(50)	(50)
Total change in other comprehensive income for year	$ (8,995)	$(33,446)	$ 2,332	$ (795)	$ 607	$(2,466)

The estimated net loss (gain) and prior service cost (credit) for the pension plans that will be amortized from accumulated OCI into net periodic benefit cost in 2011 are $10.8 million and $(1.6) million, respectively. The estimated net loss (gain) and prior service cost (credit) for the SERP that will be amortized from accumulated OCI into net periodic benefit cost in 2011 are $1.2 million and $0.6 million, respectively. The estimated net loss (gain), prior service cost (credit) and transition obligation (asset) for the other postretirement plans that will be amortized from accumulated OCI into net periodic benefit cost in 2011 total $(0.3) million.

The aggregate expected contributions by the Company to fund the retirement plan, SERP and the other postretirement plans for the year ending December 31, 2011 are expected to be at least $5.0 million, $3.5 million and $0.5 million, respectively.

As a result of the Patient Protection and Affordable Care Act of 2010, PSE recorded a one-time tax expense of $0.8 million during the three months ended March 31, 2010, related to a Medicare D subsidy that PSE receives. These subsidies have been non-taxable in the past and will be subject to federal income taxes after 2012 as a result of the legislation.

As part of PSE's new contract with the International Brotherhood of Electrical Workers (IBEW) Local 77 union, which took effect September 1, 2010, the benefit calculation formula has changed for Company employees covered by the contract. IBEW represented employees hired after August 31, 2010 and employees not vested in a plan benefit as of July 31, 2010 participate in the cash balance formula of the retirement program, with any accrued benefit converted to a beginning cash balance account. Employees who were vested in a plan benefit as of July 31, 2010 had a choice to convert to the cash balance formula or remain on a final average earnings formula based on qualified pay and years of service. All employees accruing benefits under the cash balance formula receive the same investment plan match and Company contribution. Effective December 1, 2010, the IBEW represented employees who accrue benefits under the cash balance formula receive a higher matching contribution and an additional Company contribution as compared to IBEW represented employees who are covered by the final average earnings formula. These are the same formulas applied to non-union represented employees. IBEW represented employees who were rehired after August 31, 2010, will accrue future benefits under the cash balance formula and will be able to elect to convert their prior benefits to the cash balance formula. As a result of these changes to the IBEW contract, approximately 88.0% of the employees are in the cash balance formula and approximately 12.0% of the employees are in the final average earnings formula.

Assumptions

In accounting for pension and other benefit obligations and costs under the plans, the following weighted-average actuarial assumptions were used by the Company:

	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
Benefit Obligation Assumptions	2010	2009	2010	2009	2010	2009
Discount rate [1]	5.15%	5.75%	5.15%	5.75%	5.15%	5.75%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Medical trend rate	--	--	--	--	8.00%	7.50%
Benefit Cost Assumptions						
Discount rate	5.75%	6.50% [2]	5.75%	6.50% [2]	5.75%	6.50% [2]
Rate of plan assets	8.00%	8.25%	--	--	7.80%	7.60%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Medical trend rate	--	--	--	--	8.50%	9.00%

1 *The Company calculates the present value of the pension liability using a discount rate of 5.15% which represents the single-rate equivalent of the AA rated corporate bond yield curve.*

2 *6.20% is the benefit cost discount rate use by PSE. The discount rates for the net periodic costs for PSE was different because of the discount rates in effect as of February 5, 2009, and December 31, 2008, respectively.*

The assumed medical inflation rate used to determine benefit obligations is 8.0% in 2011 grading down to 4.90% in 2012. A 1.0% change in the assumed medical inflation rate would have the following effects:

	2010		2009	
(Dollars in Thousands)	1% Increase	1% Decrease	1% Increase	1% Decrease
Effect on post-retirement benefit obligation	$ 97	$ 85	$ 131	$ 119
Effect on service and interest cost components	6	5	7	6

The Company has selected the expected return on plan assets based on a historical analysis of rates of return and the Company's investment mix, market conditions, inflation and other factors. The expected rate of return is reviewed annually based on these factors. The Company's accounting policy for calculating the market-related value of assets for the Company's retirement plan is as follows. PSE market-related value of assets is based on a five-year smoothing of asset gains/losses measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets, and is applied consistently from year to year.

The discount rates were determined by using market interest rate data and the weighted-average discount rate from Citigroup Pension Liability Index Curve. The Company also takes into account in determining the discount rate the expected changes in market interest rates and anticipated changes in the duration of the plan liabilities.

The aggregate expected contributions and payments by the Company to fund the retirement plan, SERP and the other postretirement plans for the year ending December 31, 2011 are expected to be at least $5.0 million, $3.5 million and $0.5 million, respectively.

Plan Benefits

The expected total benefits to be paid under the qualified pension plans for the next five years and the aggregate total to be paid for the five years thereafter are as follows:

(Dollars in Thousands)	2011	2012	2013	2014	2015	2016-2020
Total benefits	$ 35,400	$ 37,500	$ 38,100	$ 37,900	$ 38,700	$ 204,700

The expected total benefits to be paid under the SERP for the next five years and the aggregate total to be paid for the five years thereafter are as follows:

(Dollars in Thousands)	2011	2012	2013	2014	2015	2016-2020
Total benefits	$ 3,506	$ 2,971	$ 3,857	$ 3,238	$ 3,159	$ 17,916

The expected total benefits to be paid under the other benefits for the next five years and the aggregate total to be paid for the five years thereafter are as follows:

(Dollars in Thousands)	2011	2012	2013	2014	2015	2016-2020
Total benefits	$ 1,457	$ 1,432	$ 1,366	$ 1,299	$ 1,223	$ 6,319
Total benefits without Medicare Part D subsidy	$ 1,861	$ 1,861	$ 1,823	$ 1,782	$ 1,727	$ 7,735

Plan Assets

Plan contributions and the actuarial present value of accumulated plan benefits are prepared based on certain assumptions pertaining to interest rates, inflation rates and employee demographics, all of which are subject to change. Due to uncertainties inherent in the estimations and assumptions process, changes in these estimates and assumptions in the near term may be material to the financial statements.

The Company has a Retirement Plan Committee that establishes investment policies, objectives and strategies designed to balance expected return with a prudent level of risk. All changes to the investment policies are reviewed and approved by the Retirement Plan Committee prior to being implemented.

The Retirement Plan Committee invests trust assets with investment managers who have historically achieved above-median long-term investment performance within the risk and asset allocation limits that have been established. Interim evaluations are routinely performed with the assistance of an outside investment consultant. To obtain the desired return needed to fund the pension benefit plans, the Retirement Plan Committee has established investment allocation percentages by asset classes as follows:

	Allocation		
Asset Class	Minimum	Target	Maximum
Domestic large cap equity	25%	32%	40%
Domestic small cap equity	0%	10%	15%
Non-U.S. equity	10%	20%	30%
Tactical asset allocation	0%	5%	10%
Fixed income	15%	23%	30%
Real estate	0%	0%	10%
Absolute return	5%	10%	15%
Cash	0%	0%	5%

Plan Fair Value Measurements

Effective December 31, 2009, ASC 715 directs companies to provide additional disclosures about plan assets of a defined benefit pension or other postretirement plan. The objectives of the disclosures are to disclose the following: (1) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; (2) major categories of plan assets; (3) inputs and valuation techniques used to measure the fair value of plan assets; (4) effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and (5) significant concentrations of risk within plan assets.

In September 2009, the FASB issued ASU 2009-12, "Fair Value Measurements and Disclosures: Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent)." The standard allows the reporting entity, as a practical expedient, to measure the fair value of investments that do not have readily determinable fair values on the basis of the net asset value per share of the investment if the net asset value of the investment is calculated in a matter consistent with ASC 946, "Financial Services – Investment Companies." The standard requires disclosures about the nature and risk of the investments and whether the investments are probable of being sold at amounts different from the net asset value per share.

The following table sets forth by level, within the fair value hierarchy, the qualified pension plan assets at fair value that were accounted for at fair value on a recurring basis as of December 31, 2010 and 2009:

	Recurring Fair Value Measures As of December 31, 2010				Recurring Fair Value Measures As of December 31, 2009			
(Dollars in Thousands)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Equities:								
Non-US equity [1]	$ 54,298	$ 52,418	$ --	$ 106,716	$ 50,890	$ 48,062	$ --	$ 98,952
Domestic large cap equity [2]	144,431	28,376	--	172,807	134,754	24,641	--	159,395
Domestic small cap equity [3]	55,750	--	--	55,750	49,513	--	--	49,513
Total equities	254,479	80,794	--	335,273	235,157	72,703	--	307,860
Tactical asset allocation [4]	--	29,566	--	29,566	--	25,469	--	25,469
Fixed income securities [5]	102,314	1,982	--	104,296	43,244	51,244	--	94,488
Absolute return [6]	--	--	48,100	48,100	--	--	46,226	46,226
Cash and cash equivalents [7]	--	6,737	--	6,737	--	9,588	--	9,588
Subtotal	$ 356,793	$ 119,079	$ 48,100	$ 523,972	$ 278,401	$ 159,004	$ 46,226	$ 483,631
Net receivables				2,272				1,629
Accrued income				225				429
Total assets				$ 526,469				$ 485,689

1 *Non – US Equity investments are comprised of a (1) mutual fund; and (2) commingled fund. The investment in the mutual fund is valued using quoted market prices multiplied by the number of shares owned as of December 31, 2010. The investment in the commingled fund is valued at the net asset value per share multiplied by the number of shares held as of December 31, 2010.*

2 *Domestic large cap equity investments are comprised of (1) common stock, and (2) commingled fund. Investments in common stock are valued using quoted market prices multiplied by the number of shares owned as of December 31, 2010. The investment in the commingled fund is valued at the net asset value per share multiplied by the number of shares held as of December 31, 2010.*

3 *Domestic small cap equity investments are comprised of common stock and are valued using quoted market prices multiplied by the number of shares owned as of December 31, 2010.*

4 *The tactical asset allocation investment are compromised of a commingled fund, which is valued at the net asset value per share multiplied by the number of shares held as of the measurement date.*

5 *Fixed income securities consist of a mutual fund, convertible securities, corporate bonds, and mortgage backed mortgage pools guaranteed by GNMA, FNMA and FHLMC. The investment in the mutual fund is valued using quoted market prices multiplied by the number of shares owned as of December 31, 2010. The other investments are valued using various valuation techniques and sources such as value generation models, broker quotes, benchmark yields and/or other applicable data.*

6 *Absolute return investments consist of a mutual fund and two partnerships. The mutual fund is valued using the net asset value per share multiplied by the number of shares held as of December 31, 2010. The partnership is valued using the financial reports as of December 31, 2010. These investments are a Level 3 under ASC 820 because the plan does not have the ability to redeem the investment in the near-term at the net asset value per share.*

7 *The investment consists of a money market fund, which is valued at the net asset value per share of $1.00 per unit as of December 31, 2010. The money market fund invests primarily in commercial paper, notes, repurchase agreements, and other evidences of indebtedness which are payable on demand or which have a maturity date not exceeding thirteen months from the date or purchase.*

Level 3 Roll-Forward

The following table sets forth a reconciliation of changes in the fair value of the plan's Level 3 assets for the years ended December, 31, 2010 and 2009:

	As of December 31, 2010			As of December 31, 2009		
(Dollars in Thousands)	Partnership	Mutual Funds	total	Partnership	Mutual Funds	Total
Balance at beginning of year	$ 23,214	$ 23,012	$ 46,226	$ 20,514	$ 19,137	$ 39,651
Additional investments	10,473	--	10,473	--	--	--
Distributions	--	(11,716)	(11,716)	--	--	--
Realized losses on distributions	--	(1,370)	(1,370)	--	--	--
Unrealized gains relating to instruments still held at the reporting date	1,794	2,693	4,487	2,700	3,875	6,575
Balance at end of year	$ 35,481	$ 12,619	$ 48,100	$ 23,214	$ 23,012	$ 46,226

The following table sets forth by level, within the fair value hierarchy, the Other Benefits plan assets at fair value as of December 31, 2010 and 2009:

	Recurring Fair Value Measures as of December 31, 2010			Recurring Fair Value Measures as of December 31, 2009		
(Dollars in Thousands)	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Mutual fund [1]	$ 8,115	$ --	$ 8,115	$ 8,321	$ --	$ 8,321
Cash equivalents [2]	--	173	173	--	469	469
Total assets	$ 8,115	$ 173	$ 8,288	$ 8,321	$ 469	$ 8,790

1 *This is a publicly traded balanced mutual fund. The fund seeks regular income, conservation of principal, and an opportunity for long-term growth of principal and income. The fair value is determined by taking the number of shares owned by the plan, and multiplying by the market price as of December 31, 2010.*

2 *This consists of a deposit fund and a money market fund. The fair value of the deposit fund is calculated by using the financial reports available as of December 31, 2010. The money market fund investments are valued at the net asset value per share of $1.00 per unit as of December 31, 2010. The money market fund invests primarily in commercial paper, notes, repurchase agreements, and other evidences of indebtedness which are payable on demand or which have a maturity date not exceeding thirteen months from the date or purchase.*

(15) Stock-based Compensation Plans

Prior to the merger on February 6, 2009, the Company granted equity awards, including stock awards, performance awards, stock options and restricted stock to officers and key employees of the Company under the Company's Long-Term Incentive Plan (LTI Plan), approved by the shareholders in 2005. Any shares awarded were either purchased on the open market or were a new issuance. With the completion of the merger, all shares outstanding under the LTI Plan were fully vested and settled in cash to plan participants. Puget Energy paid and recognized $14.5 million of merger expense in connection to the vesting of the LTI Plan shares.

Performance Share Grants

The Company generally awarded performance share grants annually under the LTI Plan to key employees which vested at the end of three years. The number of shares awarded and the amount of expense recorded depended on Puget Energy's performance as compared to other companies and service quality indices for customer service. Compensation expense related to performance share grants was $9.6 million and $3.7 million for 2009 and 2008, respectively. The weighted-average fair value per performance share granted for the year ended 2008 was $26.72.

Performance shares activity from December 31, 2008 to February 5, 2009 was as follows:

Predecessor	Number of Shares	Weighted-Average Fair Value Per Share
Total at December 31, 2008:	244,390	$ 25.65
Granted	--	--
Vested	(244,390)	25.65
Forfeited	--	--
Performance Shares Outstanding at February 5, 2009:	--	$ --

Plan participants meeting the Company's stock ownership guidelines could elect to be paid up to 50.0% of the share award in cash. The portion of the performance share grants that could be paid in cash was classified and accounted for as a liability. As a result, the compensation expense of these liability awards was recognized over the performance period based on the fair value (i.e., cash value) of the award, and was periodically updated based on expected ultimate cash payout. Compensation cost recognized during the performance period for the liability portion of the performance grants was based on the closing price of the Company's common stock on the date of measurement and the number of months of service rendered during the period. The equity portion was valued based on the closing price of the Company's common stock on the grant date. In connection with the completion of the merger in 2009, all performance shares vested and the Company paid and recognized $9.6 million recorded in merger and related costs for such shares.

Stock Options

In 2002, Puget Energy's Board of Directors granted 40,000 stock options under the LTI Plan and an additional 260,000 options outside the LTI Plan (for a total of 300,000 non-qualified stock options) to the former President and Chief Executive Officer. These options could be exercised at the grant date market price of $22.51 per share and vested annually over four and five years, respectively. The fair value of the stock option award was estimated at $3.33 per share on the date of grant using the Black-Scholes option valuation model. The options were cancelled at the time of the merger and $2.3 million was paid in cash to the former President and Chief Executive Officer based on the terms of the merger agreement.

Restricted Stock

Restricted stock activity for the year ended December 31, 2009 was as follows:

Predecessor	Number of Shares	Weighted-Average Fair Value Per Share
Restricted Stock Outstanding at December 31, 2008:	227,643	$ 24.64
Granted	--	--
Vested	(227,643)	24.64
Forfeited	--	--
Restricted Stock Outstanding at February 5, 2009:	--	$ --

Compensation expense related to the restricted shares was $2.2 million and $2.4 million for 2009 and 2008, respectively.

Retirement Equivalent Stock

Prior to the merger on February 6, 2009, the Company had a retirement equivalent stock agreement under which in lieu of participating in the Company's SERP, the former President and Chief Executive Officer was granted performance-based stock equivalents in January of each year, which were deferred under the Company's deferred compensation plan. Retirement equivalent stock activity was as follows:

	Number of Shares	Weighted -Average Fair Value Per Share
Retirement Equivalent Stock Awarded:		
2008	7,574	$ 27.43

All shares vested in May 2008. Compensation expense related to the retirement equivalent stock agreement was $0.3 million in 2008. All equivalent stock units vested prior to the merger.

Non-Employee Director Stock Plan

Prior to February 6, 2009, the Company had a non-employee director stock plan for all non-employee directors of Puget Energy and PSE. An amended and restated plan was approved by shareholders in 2005. Under the plan, non-employee directors received a portion of their quarterly retainer fees in Puget Energy stock except that 100.0% of quarterly retainers were paid in Puget Energy stock until the director held a number of shares equal in value to two years of their retainer fees. Directors could choose to continue to receive their entire retainer in Puget Energy stock. The compensation expense related to the director stock plan was $0.4 million and $0.7 million in 2009 and 2008, respectively. As of December 31, 2008, the number of shares that had been purchased for the director stock plan was 62,362 and the number of shares deferred was 121,253, for a total of 183,615 shares. The director stock plan was terminated on February 6, 2009 by action of the Board of Directors upon completion of the merger and outstanding shares thereunder were settled.

(16) Income Taxes

The details of income tax expense are as follows:

Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2010	 2009
Charged to operating expenses:		
Current:		
Federal	$ 32,331	$ (126,156)
State	385	(901)
Deferred:		
Federal	(31,346)	194,701
State	(1,248)	--
Total income tax expense	$ 122	$ 67,644

The following reconciliation compares pre-tax book income at the federal statutory rate of 35.0% to the actual income tax expense in the Statements of Income:

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2010	2009
Income taxes at the statutory rate	$ 9,176	$ 79,414
Increase (decrease):		
Production tax credit	(19,972)	(19,741)
AFUDC excluded from taxable income	(9,970)	(7,097)
Capitalized interest	8,244	5,942
Utility plant differences	6,162	5,795
Tenaska gas contract	5,889	4,478
Other - net	593	(1,147)
Total income tax expense	$ 122	$ 67,644
Effective tax rate	0.5%	29.8%

The Company's deferred tax liability at December 31, 2010 and 2009 is composed of amounts related to the following types of temporary differences:

Puget Sound Energy	At December 31	
(Dollars In Thousands)	2010	2009
Utility plant and equipment	$ 1,099,857	$ 930,946
Regulatory asset for income taxes	73,337	89,303
Storm damage	36,286	37,002
Other deferred tax liabilities	85,206	78,583
Subtotal deferred tax liabilities	1,294,686	1,135,834
Net operating loss carryforward	(105,140)	--
Fair value of derivative instruments	(85,394)	(53,271)
Production tax credit	(60,613)	(45,730)
Pensions and other compensation	(31,312)	(35,290)
Other deferred tax assets	(57,142)	(41,343)
Subtotal deferred tax assets	(339,601)	(175,634)
Total	$ 955,085	$ 960,200

The above amounts have been classified in the Balance Sheets as follows:

Puget Sound Energy	At December 31	
(Dollars in Thousands)	2010	2009
Current deferred taxes	$ (80,216)	$ (38,115)
Non-current deferred taxes	1,035,301	998,315
Total	$ 955,085	$ 960,200

The Company calculates its deferred tax assets and liabilities under ASC 740. ASC 740 requires recording deferred tax balances, at the currently enacted tax rate, on assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes. The utilization of deferred tax assets requires sufficient taxable income in the future years. ASC 740 requires a valuation allowance on deferred tax assets when it is more likely than not that the deferred tax asset will not be realized. The

Company's PTC carryforwards expire from 2027 through 2030. The Company's net operating loss carryforwards expire from 2029 through 2030.

For ratemaking purposes, deferred taxes are not provided for certain temporary differences. PSE has established a regulatory asset for income taxes recoverable through future rates related to those temporary differences for which no deferred taxes have been provided, based on prior and expected future ratemaking treatment.

The Company accounts for uncertain tax position under ASC 740, which clarifies the accounting for uncertainty in income taxes recognized in the financial statements. ASC 740 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, a tax position should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by the taxing authority. Second, a tax position that meets the recognition threshold should be measured at the largest amount that has a greater than 50.0% likelihood of being sustained.

As of December 31, 2010 and 2009, the Company had no material unrecognized tax benefits. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year.

For ASC 740 purposes, the Company has open tax years from 2006 through 2010. The Company is under audit by the IRS for tax years 2006 and 2008. The Company classifies interest as interest expense and penalties as other expense in the financial statements.

(17) Litigation

Proceedings Relating to the Western Power Market

The following discussion summarizes the status as of the date of this report of ongoing proceedings relating to the western power markets to which PSE is a party. PSE is vigorously defending the remaining claims. Litigation is subject to numerous uncertainties and PSE is unable to predict the ultimate outcome of these matters. Accordingly, there can be no guarantee that these proceedings will not materially and adversely affect PSE's financial condition, results of operations or liquidity.

Pacific Northwest Refund Proceeding. In October 2000, PSE filed a complaint with the FERC (Docket No. EL01-10) against "all jurisdictional sellers" in the Pacific Northwest seeking prospective price caps consistent with any result the FERC ordered for the California markets. The FERC issued an order including price caps in July 2001, and PSE moved to dismiss the proceeding. In response to PSE's motion, various entities intervened and sought to convert PSE's complaint into one seeking retroactive refunds in the Pacific Northwest. The FERC rejected that effort, after holding what the FERC referred to as a "preliminary evidentiary hearing" before an administrative law judge. In April 2009, the Ninth Circuit rejected the requests for rehearing filed in this matter and remanded the proceeding to the FERC. The FERC is now considering what response to take to the Court remand order, as petitions for review by the Supreme Court were denied on January 11, 2010. PSE intends to vigorously defend its position but is unable to predict the outcome of this matter.

Proceedings Relating to Colstrip

In May 2003, approximately 50 plaintiffs initiated an action against the owners of Colstrip regarding pond seepage, The defendants reached an agreement on a global settlement with all plaintiffs and PSE expensed its share of the settlement in 2008. PSE received a partial reimbursement for its share from insurers in December 2010 and January 2011.

On March 29, 2007, a second complaint related to pond seepage was filed on behalf of two ranch owners alleging damage due to the Colstrip Units 3 & 4 effluent holding pond. A mediation between plaintiffs and PPL Montana, LLC, the operator of Units 3 & 4, took place in July 2010 and parties are working toward a final settlement.

Proceedings Related to Bonneville Power Administration

Petitioners in several actions in the Ninth Circuit against the BPA asserted that the BPA acted contrary to law in entering into or performing or implementing a number of agreements, including the amended settlement agreement (and the May 2004 agreement) between the BPA and PSE regarding the REP. Petitioners in several actions in the Ninth Circuit against the BPA also asserted that the BPA acted contrary to law in adopting or implementing the rates upon which the benefits received or to be received from the BPA during the October 1, 2001 through September 30, 2006 period were based. A number of parties claimed that the rates the BPA proposed or adopted in the BPA rate proceeding to develop the BPA rates to be used in the agreements for determining the amounts of money to be paid to PSE by the BPA during the period October 1, 2006 through September 30, 2009 are contrary to law. Furthermore, the parties claimed the BPA acted contrary to law or without authority in deciding to enter into, or in entering into or performing or implementing such agreements.

On May 3, 2007, the Ninth Circuit issued an opinion in *Portland Gen. Elec. v. BPA*, Case No. 01-70003, in which proceeding the actions of the BPA in entering into settlement agreements regarding the REP with PSE and with other investor-owned utilities were challenged. In this opinion, the Ninth Circuit granted petitions for review and held the settlement agreements entered into between the BPA and the investor-owned utilities being challenged in that proceeding to be inconsistent with statute. On May 3, 2007, the Ninth Circuit also issued an opinion in *Golden Northwest Aluminum v. BPA*, Case No. 03-73426, in which proceeding the petitioners sought review of BPA's 2002-2006 power rates. In this opinion, the Ninth Circuit granted petitions for review and held that the BPA unlawfully shifted onto its preference customers the costs of its settlements with the investor-owned utilities. On October 11, 2007, the Ninth Circuit remanded the May 2004 agreement to the BPA in light of the *Portland Gen. Elec. v. BPA* opinion and dismissed the remaining three pending cases regarding settlement agreements.

In March 2008, the BPA and PSE signed an agreement pursuant to which BPA made a payment to PSE related to the REP benefits for the fiscal year ended September 30, 2008, which payment is subject to true-up depending upon the amount of any REP benefits ultimately determined to be payable to PSE.

In September 2008, the BPA issued its record of decision in its reopened WP-07 rate proceeding to respond to the various Ninth Circuit opinions. In this record of decision, the BPA adjusted its fiscal year 2009 rates, determined the amounts of REP benefits it considered to have been improperly paid after fiscal year 2001 to PSE and the other regional investor-owned utilities, and determined that such amounts are to be recovered through reductions in REP benefit payments to be made over a number of years. The amount determined by the BPA to be recovered through reductions commencing October 2007 in REP payments for PSE's residential and small farm customers was approximately $207.2 million plus interest on unrecovered amounts to the extent that PSE receives any REP benefits for its customers in the future. However, these BPA determinations are subject to subsequent administrative and judicial review, which may alter or reverse such determinations. PSE and others, including a number of preference agency and investor-owned utility customers of the BPA, in December 2008 filed petitions for review in the Ninth Circuit of various of these BPA determinations. Any change to the REP would be passed to customers.

In September 2008, the BPA and PSE signed a short-term Residential Purchase and Sale Agreement (RPSA) under which the BPA is to pay REP benefits to PSE for fiscal years ending September 30, 2009–2011. In December 2008, the BPA and PSE signed another, long-term RPSA under which the BPA is to pay REP benefits to PSE for the period October 2011 through September 2028. PSE and other customers of BPA in December 2008 filed petitions for review in the Ninth Circuit of the short-term and long-term RPSAs signed by PSE (and similar RPSAs signed by other investor-owned utility customers of the BPA) and the BPA's record of decision regarding such RPSAs. Generally, REP benefit payments under a RPSA are based on the amount, if any, by which a utility's average system cost exceeds the BPA's Priority Firm (PF) Exchange rate for such utility. The average system cost for a utility is determined using an average system cost methodology adopted by the BPA. The average system cost methodology adopted by the BPA and the average system cost determinations, REP overpayment determinations, and the PF Exchange rate determinations by the BPA are all subject to FERC review or judicial review or both and are subject to adjustment, which may affect the amount of REP benefits paid or to be paid by the BPA to PSE. As discussed above, the BPA has determined to reduce such payments based on its determination of REP benefit overpayments after fiscal year 2001.

It is not clear what impact, if any, such development or review of such the BPA rates, average system cost, average system cost methodology, and the BPA determination of REP overpayments, review of such agreements, and the above described Ninth Circuit litigation may ultimately have on PSE.

Snoqualmie Falls

On July 7, 2010, a lawsuit was filed in the U.S. District Court for the Western District of Washington by the Snoqualmie Valley Preservation Alliance, a group of downstream landowners, against the United States Army Corps of Engineers (Corps) challenging permits issued by the Corps in connection with the redevelopment of the Snoqualmie Falls Hydroelectric Project. Plaintiffs request an order to stop work at the project pending further review of downstream impacts. PSE sought and was granted permission to intervene in the proceeding. Motions for summary judgment have been filed by the plaintiff and the Corps. PSE joined the Corps' motion and filed a motion for summary judgment arguing the plaintiff's claims are barred as untimely and improper. The parties await a determination by the Court. The ultimate impact of the suit, if any, on PSE or the work currently underway on the project cannot be determined at this time. The construction schedule has not been impacted by the lawsuit.

(18) Commitments and Contingencies

For the year ended December 31, 2010, approximately 19.2% of the Company's energy output was obtained at an average cost of approximately $0.018 per kilowatt hour (kWh) through long-term contracts with three of the Washington Public Utility Districts (PUDs) that own hydroelectric projects on the Columbia River. The purchase of power from the Columbia River projects is on a pro rata share basis under which the Company pays a proportionate share of the annual debt service, operating and maintenance costs and other expenses associated with each project in proportion to the contractual shares that PSE obtains from that project. In these instances, PSE's payments are not contingent upon the projects being operable; therefore, PSE is required to make the payments even if power is not delivered. These projects are financed through substantially level debt service payments and their annual costs should not vary significantly over the term of the contracts unless additional financing is required to meet the costs of major maintenance, repairs or replacements, or license requirements. The Company's share of the costs and the output of the projects is subject to reduction due to various withdrawal rights of the PUDs and others over the contract lives.

The following table summarizes the Company's estimated payment obligations for power purchases from the Columbia River projects, contracts with other utilities and contracts under non-utility generators under the Public Utility Regulatory Policies Act. These contracts have varying terms and may include escalation and termination provisions.

(Dollars in Thousands)	2011	2012	2013	2014	2015	Thereafter	Total
Columbia River projects	$ 110,054	$ 73,390	$ 70,364	$ 72,543	$ 72,895	$ 820,167	$ 1,219,413
Other utilities	140,830	131,783	71,984	53,042	45,331	297,649	740,619
Non-utility generators	149,195	--	--	--	--	--	149,195
Total	$ 400,079	$ 205,173	$ 142,348	$ 125,585	$ 118,226	$ 1,117,816	$ 2,109,227

Total purchased power contracts provided the Company with approximately 8.2 million, 8.3 million and 8.7 million megawatt hours (MWh) of firm energy at a cost of approximately $420.6 million, $363.3 million and $384.0 million for the years 2010, 2009 and 2008, respectively.

As part of its electric operations and in connection with the 1997 restructuring of the Tenaska Power Purchase Agreement, PSE is obligated to deliver to Tenaska up to 50,000 MMBtu (one million British thermal units, equal to one Dekatherm (Dth)) per day of natural gas for operation of Tenaska's natural gas-fired cogeneration facility. This obligation continues for the remaining term of the agreement, through December 31, 2011, provided that no deliveries are required during the month of May. The price paid by Tenaska for this natural gas is reflective of the daily price of natural gas at the United States/Canada border near Sumas, Washington.

The Company has natural gas-fired generation facility obligations for natural gas supply amounting to an estimated $65.5 million in 2011. Longer term agreements for natural gas supply amount to an estimated $137.2 million for 2012 through 2029.

PSE enters into short-term energy supply contracts to meet its core customer needs. These contracts are generally classified as NPNS or in some cases recorded at fair value in accordance with ASC 815. Commitments under these contracts are $86.0 million, $51.4 million and $9.3 million in 2011, 2012 and 2013, respectively.

Natural Gas Supply Obligations

The Company has also entered into various firm supply, transportation and storage service contracts in order to ensure adequate availability of natural gas supply for its firm customers. Many of these contracts, which have remaining terms from less than one year to 34 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. The Company contracts for its long-term natural gas supply on a firm basis, which means the Company has a 100% daily take obligation and the supplier has a 100% daily delivery obligation to ensure service to PSE's customers and generation requirements. The Company incurred demand charges in 2010 for firm natural gas supply, firm transportation service and firm storage and peaking service of $0.4 million, $136.5 million and $7.1 million, respectively. The Company incurred demand charges in 2010 for firm transportation and firm storage service for the natural gas supply for its combustion turbines in the amount of $27.7 million, which is included in the total Company demand charges.

The following table summarizes the Company's obligations for future demand charges through the primary terms of its existing contracts. The quantified obligations are based on current contract prices and the FERC authorized rates, which are subject to change.

Demand Charge Obligations (Dollars in Thousands)	2011	2012	2013	2014	2015	Thereafter	Total
Firm transportation service	$144,529	$137,305	$128,759	$104,790	$ 62,667	$ 328,864	$906,914
Firm storage service	9,241	8,638	2,997	1,507	1,507	7,077	30,967
Firm natural gas supply	553	525	262	--	--	--	1,340
Total	$154,323	$146,468	$132,018	$106,297	$ 64,174	$ 335,941	$939,221

Service Contracts

The following table summarizes the Company's estimated obligations for service contracts through the terms of its existing contracts.

Service Contract Obligations (Dollars in Thousands)	2011	2012	2013	2014	2015	Thereafter	Total
Automated meter reading system	$ 35,261	$ 36,166	$ 37,234	$ 38,344	$ 39,501	$ 10,176	$196,682
Energy production service contracts [1]	23,477	18,994	19,360	20,124	26,730	49,948	158,633
Information technology service contracts	26,473	22,100	13,907	--	--	--	62,480
Total	$ 85,211	$ 77,260	$ 70,501	$ 58,468	$ 66,231	$ 60,124	$417,795

1 *Energy production service contracts include operations and maintenance contracts on Mint Farm, Wild Horse, Goldendale electric generating facility (Goldendale), Hopkins Ridge and Sumas facilities.*

Surety Bond

The Company has a self-insurance surety bond in the amount of $4.3 million, which expires on July 1, 2011 and is renewed annually, guaranteeing compliance with the Industrial Insurance Act (workers' compensation) and nine self-insurer's pension bonds totaling $1.5 million.

Environmental Remediation

The Company is subject to environmental laws and regulations by the federal, state and local authorities and is required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The Company has been named by the Environmental Protection Agency (EPA), the Washington State Department of Ecology and/or other third parties as potentially responsible at several contaminated sites and manufactured gas plant sites. PSE has implemented an ongoing program to test, replace and remediate certain underground storage tanks (UST) as required by federal and state laws. The UST replacement component of this effort is finished, but PSE continues its work remediating and/or monitoring relevant sites. During 1992, the Washington Commission issued orders regarding the treatment of costs incurred by the Company for certain sites under its environmental remediation program. The orders authorize the Company to accumulate and defer prudently incurred cleanup costs paid to third parties for recovery in rates established in future rate proceedings, subject to Washington Commission review. The Washington Commission consolidated the gas and electric methodological approaches to remediation and deferred accounting in an order issued October 8, 2008. Per the guidance of ASC 450, "Contingencies", the Company reviews its estimated future obligations and adjusts loss reserves quarterly. Management believes it is probable and reasonably estimable that the impact of the potential outcomes of disputes with certain property owners and other potentially responsible parties will result in environmental remediation costs ranging from $38.8 million to $55.8 million for gas and from $8.2 million to $27.8 million for electric. The Company does not consider any amounts within those ranges as being a better estimate and has therefore accrued $38.8 million and $8.2 million for gas and electric, respectively. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order. For the year ended December 31, 2010, the Company incurred deferred electric and natural gas environmental costs of $7.6 million and $54.7 million, net of insurance proceeds, respectively.

(19) Other

2010 Out-of-period disclosure. During the second quarter of 2010, management corrected accounting errors in the Companies' financial statements that resulted in an increase to depreciation expense of $2.2 million, a net decrease to electric revenue and purchased electricity of $1.8 million and a decrease to income tax expense of $1.5 million.

The impact of correcting these errors in prior periods would have reduced PSE's net income by $1.1 million in 2009. Management determined these errors were not material to the prior annual or interim periods or to the current annual or interim periods in which they are being corrected and, therefore, the Company recorded a reduction to PSE's net income of $2.4 million for the year ended December 31, 2010.

(20) Segment Information

PSE is a regulated utility segment includes the account receivables securitization program which was terminated during the merger. The service territory of PSE covers approximately 6,000 square miles in the state of Washington.

Non-utility business segment includes two PSE subsidiaries is described as Other. The PSE subsidiaries are a real estate investment and development company and a holding company for a small non-utility wholesale generator which was sold in 2010. Reconciling items between segments are not significant.

Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2010 Regulated Utility	Other	Total
Revenue	$3,121,935	$ 282	$ 3,122,217
Depreciation and amortization	364,204	2	364,206
Income tax expense	60	62	122
Operating income	207,647	(56)	207,591
Interest charges, net of AFUDC	220,854	--	220,854
Net income	26,358	(263)	26,095
Total assets	9,260,675	50,109	9,310,784
Construction expenditures - excluding equity AFUDC	859,091	--	859,091

Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2009 Regulated Utility	Other	Total
Revenue	$ 3,325,263	$ 3,238	$3,328,501
Depreciation and amortization	332,646	206	332,852
Income tax (benefit) expense	69,890	(2,246)	67,644
Operating income	387,652	(4,517)	383,135
Interest charges, net of AFUDC	202,527	--	202,527
Net income	161,508	(2,256)	159,252
Total assets	8,765,189	51,382	8,816,571
Construction expenditures - excluding equity AFUDC	775,688	--	775,688

(21) Related Party Transactions

On June 1, 2006, PSE entered into a revolving credit facility with Puget Energy in the form of a Demand Promissory Note (Note). Through the Note, PSE may borrow up to $30.0 million from Puget Energy, subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lowest of the weighted-average interest rate of PSE's outstanding commercial paper interest rate or PSE's senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. At December 31, 2010 and December 31, 2009, the outstanding balance of the Note was $22.6 million and $22.9 million, respectively, and the interest rate was 1.1% and 1.2%, respectively. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements. The $30.0 million credit facility with Puget Energy was unaffected by the merger.

On December 6, 2010, Puget Energy issued $450.0 million of senior secured notes. Net proceeds of $443.0 million from these notes were used to repay a portion of the $1.225 billion term-loan. Puget Energy's term-loan and facility for funding capital expenditures mature in 2014, contain similar terms and conditions and are syndicated among numerous committed banks and other financial institutions. One of these banks is Macquarie Bank Limited, which has commitments of $48.0 million under the term-loan and $20.6 million under the capital expenditure credit facility. Concurrent with the borrowings under these credit agreements, Puget Energy entered into several interest rate swap instruments to hedge volatility associated with these two loans. Two of the swap

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-111048 and UG-111049
Puget Sound Energy, Inc.'s
2011 General Rate Case

ICNU DATA REQUEST NO. 10.02

ICNU DATA REQUEST NO. 10.02:

Referring to pages 7 and 8 of Mr. Gaines' rebuttal testimony, please cite the Washington Utilities & Transportation Commission ("WUTC") order identifying the removal of Other Comprehensive Income from Regulated Common Equity as reasonable.

Response:

Puget Sound Energy, Inc. ("PSE") could find no Commission orders from prior PSE proceedings that specifically address the appropriate treatment of Other Comprehensive Income ("OCI") with respect to regulated common equity or the capital structure.

However, in Order 07 in PacifiCorp Docket No. UE-100749 (May 12, 2011, page 7, paragraph 16), the Commission stated, in reviewing a capital structure proposed by ICNU:

> We found persuasive ICNU's arguments that the Company was maintaining large temporary cash investments (not "cash deposits") on its balance sheet that were **not being used for utility plant operations, and therefore should be excluded from common equity**.

(emphasis added)

It seems clear from this statement that the Commission intends to only include in the capital structure the common equity that is supporting utility operations. Clearly retained earnings from non-utility operations such as Puget Western, Inc. ("PWI") is not supporting utility operations and thus, like these cash balances, should be excluded from common equity and the capital structure for rate making purposes.

In addition, PSE could find no order in which the Commission included PSE's pension assets in rate base. As a result, it is reasonable that the impact on common equity from pension accounting should be removed from the capital structure.

Likewise, the Commission does not reflect in rates the non-cash unrealized gains and losses from marking derivative contracts to market. Therefore, it is reasonable to exclude from the capital structure other side of these accounting entries - the impacts on common equity resulting from these accounting marks in OCI.

Attached as Attachment A to PSE's Response to ICNU Data Request No 10.02, please find page 7 from Order 07 in Docket UE-100749, dated May 12, 2011.

CROSS-EXAMINATION EXHIBITS OF ICNU – David E. Mills			
Mills, DEM-15CCX	David E. Mills	PSE	Confidential Sumas Price Comparison

Sumas Price Comparison
($/MMBTU)

Month	PSE Rebuttal Sept 9, 2011 - Dec 8, 2011[1/]	Nov 7, 2011 - Feb 6, 2012[2/]	Change
May-12	[redacted]	[redacted]	[redacted]
Jun-12	[redacted]	[redacted]	[redacted]
Jul-12	[redacted]	[redacted]	[redacted]
Aug-12	[redacted]	[redacted]	[redacted]
Sep-12	[redacted]	[redacted]	[redacted]
Oct-12	[redacted]	[redacted]	[redacted]
Nov-12	[redacted]	[redacted]	[redacted]
Dec-12	[redacted]	[redacted]	[redacted]
Jan-13	[redacted]	[redacted]	[redacted]
Feb-13	[redacted]	[redacted]	[redacted]
Mar-13	[redacted]	[redacted]	[redacted]
Apr-13	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]

[1/] Information provided by PSE in rebuttal workpapers:
EXCEL file DEM-WP(C) Gas Forward Marks_2011GRC_Rebuttal.xls
[2/] Information obtained from Sungard Kiodex on February 7, 2012.

CROSS-EXAMINATION EXHIBITS OF ICNU – Wayne R. Gould			
Gould, WRG-9CX	Wayne R. Gould	PSE	ICNU Revision to PSE Exh. No. ___(WRG-5)
Gould, WRG-10CX	Wayne R. Gould	PSE	PSE Exh. No. ___(WRG-6)
Gould, WRG-11CX	Wayne R. Gould	PSE	Worksheet WRG-3 Summary Correction 2-8-2012

Comparison of Test Period versus Budget for PSE's Gas-Fired Plants

WRG-6

Plant	Test Year Adjusted Expense	2012 Budgeted Production O&M Expense	2013 Budgeted Production O&M Expense	Rate Year Budgeted O&M (monthly spreads)
Encogen	4,188,153	4,575,839	4,452,453	4,901,036
CPC - Freddie 1	4,462,023	4,347,740	4,489,042	4,394,766
Crystal	111,244	153,045	150,525	141,314
Goldendale	6,563,400	8,501,728	10,533,004	8,524,447
Mint Farm	7,970,116	6,558,845	7,246,256	6,361,528
Whitehorn	1,084,012	1,586,525	1,531,282	1,516,028
Frederickson	6,909,823	1,229,850	1,420,851	1,294,575
Fredonia 1-4	3,579,096	2,883,235	2,561,628	2,861,678
Sumas	5,436,912	5,309,678	5,741,490	5,241,892
Undistributed	4,198,991	4,140,032	4,480,936	4,228,991
Colstrip, Hydro, Wind & System Control & Dispatch	90,172,134	95,928,240	100,773,266	101,920,990
Total	**134,675,904**	**135,214,757**	**143,380,734**	**141,387,244**
	Excess of rate year O&M over test year O&M			**6,711,339**

WRG-6 SCCTs and CCCT

Plant	Test Year Adjusted Expense	2012 Budgeted Production O&M Expense	2013 Budgeted Production O&M Expense	Rate Year Budgeted O&M (monthly spreads)
Encogen	4,188,153	4,575,839	4,452,453	4,901,036
CPC - Freddie 1	4,462,023	4,347,740	4,489,042	4,394,766
Goldendale	6,563,400	8,501,728	10,533,004	8,524,447
Mint Farm	7,970,116	6,558,845	7,246,256	6,361,528
Whitehorn	1,084,012	1,586,525	1,531,282	1,516,028
Frederickson	6,909,823	1,229,850	1,420,851	1,294,575
Fredonia 1-4	3,579,096	2,883,235	2,561,628	2,861,678
Sumas	5,436,912	5,309,678	5,741,490	5,241,892
Total	**40,193,535**	**34,993,439**	**37,976,006**	**35,095,949**
	Excess of rate year O&M over test year O&M			**(5,097,586)**

WRG-6 SCCTs, CCCT and Undistributed

Plant	Test Year Adjusted Expense	2012 Budgeted Production O&M Expense	2013 Budgeted Production O&M Expense	Rate Year Budgeted O&M (monthly spreads)
Encogen	4,188,153	4,575,839	4,452,453	4,901,036
CPC - Freddie 1	4,462,023	4,347,740	4,489,042	4,394,766
Goldendale	6,563,400	8,501,728	10,533,004	8,524,447
Mint Farm	7,970,116	6,558,845	7,246,256	6,361,528
Whitehorn	1,084,012	1,586,525	1,531,282	1,516,028
Frederickson	6,909,823	1,229,850	1,420,851	1,294,575
Fredonia 1-4	3,579,096	2,883,235	2,561,628	2,861,678
Sumas	5,436,912	5,309,678	5,741,490	5,241,892
Undistributed	4,198,991	4,140,032	4,480,936	4,228,991
Total	**44,392,525**	**39,133,471**	**42,456,942**	**39,324,940**
	Excess of rate year O&M over test year O&M			**(5,067,586)**

Bold ##'s reflect change from as filed.

Ln.		Core O&M	Contract Major Maintenance	Non-Contract Major Maintenance	Other O&M: Discretionary Benefits	Other O&M: JP Storage	Other O&M: Other	Total Production O&M	Note
1	**PSE Proposal**								
2	PSE Supplemental	$ 123,811,739	$ 1,132,622	$8,159,198	$770,484	1,130,625.00	2,601,706.88	$ 137,606,374	
3	PSE Adjustments (*)								
4	Colstrip Budget Update	(2,626,645)						(2,626,645)	
5	Normalization of Non-Contract MM							-	
6	Update JP Storage to Current Contract					(303,825)		(303,825)	
7	PSE Rebuttal	$ 121,185,094	$ 1,132,622	$ 8,159,198	$ 770,484	$ 826,800	$ 2,601,707	$ 134,675,904	
8									
9	**ICNU Proposal**								
10	PSE Supplemental	$ 123,811,739	$ 1,132,622	$ 8,159,198	$ 770,484	$ 1,130,625	$ 2,601,707	137,606,374	
11	ICNU Adjustments (*)								
12	Four year normalization of all production O&M for Frederickson, Fredonia, Sumas, Mint Farm & Undistributed O&M expense.	**$ (1,674,591)**	**$ (292,747)**	**$ (5,134,378)**			$ (1,265,488)	$ (8,367,204)	
13	ICNU Response Proposal	$ 122,137,148	$ 839,874	$ 3,024,820	$ 770,484	$ 1,130,625	$ 1,336,219	$ 129,239,171	
14	Correction for errors & omissions in adjustment calculation (see WRG-05)	**$ (1,947,774)**		**$ 2,582,611**				634,836	
15	ICNU Proposal corrected for errors & omissions:	$ 120,189,374	$ 839,874	$ 5,607,431	$ 770,484	$ 1,130,625	$ 1,336,219	$ 129,874,007	
16									
17									
18	**Staff Proposal**								
19	PSE Supplemental	$ 123,811,739	$ 1,132,622	$ 8,159,198	$ 770,484	$ 1,130,625	$ 2,601,707	$ 137,606,374	
20	Staff Adjustments (*)								
21	5 year normalization of non-contract MM			(3,540,000)				(3,540,000)	
22	2012 budget for undistributed				(770,484)	**(223,706)**	**81,490**	(912,700)	(a)
23	Update JP Storage to Current Contract					**(80,119)**		(80,119)	(b)
24	Pro form contract MM to the rate year		(1,062,522)					(1,062,522)	
25	Staff Response Proposal	$ 123,811,739	$ 70,100	$ 4,619,198	$ -	$ 826,800	$ 2,683,197	$ 132,011,033	
26	correction to average calculation (see WRG-07)			534,983				534,983	
27		$ 123,811,739	$ 70,100	$ 5,154,181	$ -	$ 826,800	$ 2,683,197	$ 132,546,016	

Ties to total of lines 32 through 35 on WRG_05

Ties to cells I21 & J21 on Adjustment for N_C Mnt tab.

(*) Other adjustments to production O&M such as production adjustment and wage and incentive increases are not presented.

(a) - Other O&M -Other changed from $80,860 to $81,490. Value in JP storage changed from $0 to ($223,706) to reflect that portion of JP rental reduction included in 2012 budgeted other O&M.
(b) - JP Storage changed from ($303,825) to ($80,119) to reflect portion of reduction is now posted to the line above. Total JP Stiorage reduction remains at $303,825.

Note: Table 1, page 7, of Exh. No. ___(WRG-1T) reflects the changes herein

Calc of Core/N-C Major Maint Split: ICNU Adjustment

Ln		ICNU, Proposed Adjustment Total O&M (above)	Adjustment 4Yr Average Non-Contract MM	Adjustment Average Amort - 2010 Amort	Adjustment Undistributed Production O&M	Adjustment Core O&M
1	Frederickson	(4,031,909)	(3,333,935)			(697,975)
2	Fredonia	(1,131,100)	(1,229,324)			98,224
3	Sumas	(717,529)	(147,168)	**(64,612)**		(505,748)
4	Mint Farm	(1,221,178)	(423,951)	**(228,135)**		(569,091)
5	Undistributed	(1,265,488)			(1,265,488)	0
6	Total	(8,367,204)	(5,134,378)	(292,747)	(1,265,488)	(1,674,591)
7						
18						

Corrected cell reference. Changed reference from H27 & H28 to I27 & I28

Ln	Plant	2007 Actual	2008 Actual	2009 Actual	2010 Actual	Average Non-Contract Major Maintenance	Adjustment 4 Yr Ave N-C Major Maint vs. Test Yr	Note
19	***Average Non-Contract Major Maintenance Expense***							
20	**Plant**	**2007 Actual**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Average Non-Contract Major Maintenance**	**Adjustment 4 Yr Ave N-C Major Maint vs. Test Yr**	**Note**
21	**Legacy Units: average based upon 48 months ownership.**							
22								
23	Frederickson 1&2	143,097	0	797,868	4,758,902	1,424,967	(3,333,935)	
24	Fredonia Units 1-4	0	222,480	243,383	1,794,386	565,062	(1,229,324)	
25	**Sumas: Purchased July 2008; average based upon 30 months ownership.**							
26	Sumas Thermal Plant	0	27,695	51,350	345,687	198,519	(147,168)	(a)
27								
28	**Mint Farm: Purchased December 2007; average based upon 25 months ownership.**							
29	Mint Farm Thermal Plant	0	0	0	847,902	423,951	(423,951)	(a)
30		143,097	250,175	1,092,602	7,746,876	2,612,499	(5,134,378)	

Amortization Expense	**2007 Actual**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Average**		
SMS Amortization Expense		8,524	51,143	180,368	115,755	(64,612)	(a)
MTF Amortization Expense Maint				456,270	228,135	(228,135)	(a)
					343,890	(292,747)	

(a) - Mr. Shoenbeck used a simple average of 2009 and 2010 for Sumas and Mint Farm in his adjustment calculation; used the same methodology here.

ln		Adjustment			Calc of Core/N-C Major Maint Split: ICNU Adjustment		
		4 Year Average N-C Major Maintenance	2010 Non-Contract Major Maintenance	Adjustment 4 Yr Ave N-C Major Maint vs. Test Yr	ICNU, Proposed Adjustment Total O&M (above)	Adjustment 4Yr Average N-C MM	Core O&M
1	Frederickson	1,424,967	4,758,902	(3,333,935)	(4,031,909)	(3,333,935)	(697,975)
2	Fredonia	565,062	1,794,386	(1,229,324)	(1,131,100)	(1,229,324)	98,224
3	Sumas	169,893	345,687	(175,794)	(717,529)	(175,794)	(541,735)
4	Mint Farm	406,993	847,902	(440,909)	(1,221,178)	(440,909)	(780,269)
5	Undistributed	0	0	0	0	0	0
6	Total	2,566,915	7,746,876	(5,179,962)	(7,101,716)	(5,179,962)	(1,921,755)
7							
8							
9	**PSE correction**						
10	Whitehorn	1,300,528	0	1,300,528	1,135,256	1,300,528	(165,272)
11	Encogen	740,841	412,322	328,520	220,695	328,520	(107,824)
12	Goldendale	999,147	0	999,147	(403,954)	999,147	(1,403,101)
13	adjust Umas for 2.5 year ownership				(317,161)		(317,161)
14		3,040,516	412,322	2,628,194	634,836	2,628,194	(1,993,358)
15							
16		5,607,431	8,159,198	(2,551,767)	(6,466,880)	(2,551,767)	(3,915,113)
17			Per ICNU calc. (from summary tab)			**(5,134,378)**	**(1,967,338)**
18			Correction			**2,582,611**	**(1,947,774)**
	Undistributed	0	0	0	(1,265,488)	0	(1,265,488)

Source; (5,134,378) is from cell E14 of the summary tab. (1,967,338) is the sum of cells C14 & D14 from the summary tab.

Added lines 17 & 18 to correct logic error. Amounts carried forward to summary are supposed to represent ajustments, not the recalculated value. Line 18 (row21) carried forward to summary tab.

Removed line 5 (row7) Undistributed O&M from calculation as it is listed as a separate category on the summary sheet and is not part of recalculation of average O&M of gas fired units.

Exh. No. WRG-9CX
Witness: Wayne R. Gould

ICNU Revision to WRG-5 - Eliminates Rental Payments for Whitehorn for 2007 - 2009

ICNU's Proposed Prod'n O&M Adj:	2007	2008	2009	2010	Total	Average	Note	ave - test yr	ICNU, Proposed Adjustment
Frederickson	2,049,064	1,301,487	1,251,281	6,909,823	11,511,654	2,877,914		(4,031,909)	(4,031,909)
Fredonia	2,755,551	1,131,846	2,347,130	3,557,458	9,791,984	2,447,996	(a)	(1,131,100)	(1,131,100)
Sumas	0	1,566,788	4,001,854	5,436,912	11,005,554	4,719,383	(b)	(717,529)	(717,529)
Mint Farm	0	31,475	5,527,761	7,970,116	13,529,351	6,748,938		(1,221,178)	(1,221,178)
Undistributed	1,211,840	2,749,042	4,483,564	4,502,132	12,946,579	3,236,645		(1,265,488)	(1,265,488)
Total	6,016,455	6,780,637	17,611,590	28,376,440	58,785,121	20,030,875		(8,367,204)	(8,367,204)

PSE Recalculation of Mr. Schoenbeck's Adjustment

	2007	2008	2009	2010	Total	Average		ave - test yr
Whitehorn	652,455	5,744,822	1,395,783	1,083,894	8,876,954	2,219,239	(c)	1,135,344
Encogen	3,913,443	3,628,208	5,905,591	4,188,153	17,635,395	4,408,849	(c)	220,695
Goldendale	4,270,374	6,822,241	6,981,769	6,563,400	24,637,784	6,159,446	(c)	(403,954)
Frederickson	2,049,064	1,301,487	1,251,281	6,909,823	11,511,654	2,877,914		(4,031,909)
Fredonia	2,755,551	1,131,846	2,347,130	3,557,458	9,791,984	2,447,996	(a)	(1,131,100)
Sumas	0	1,566,788	4,001,854	5,436,912	11,005,554	4,402,222	(d)	(1,034,690)
Mint Farm	0	31,475	5,527,761	7,970,116	13,529,351	6,748,938	(e)	(1,221,178)
Total Plants	13,640,886	20,226,866	27,411,169	35,709,756	96,988,676	29,264,603		(6,466,792)
Whitehorn Rents:	1,740,147	1,739,882	144,986					

Adjustment proposed by Schoenbeck; four year average of Gas Turbine O&M expense	(8,367,204)
back out adjustment for Undistributed Production O&M (see testimony):	1,265,488
Schoenbeck adjustment Gas Fired Generation O&M excluding "other" Production O&M expense	(7,101,716)
Add: Whitehorn - omitted from Schoenbeck calculation	1,135,344
Add: Encogen - omitted from Schoenbeck calculation	220,695
Add: Goldendale- omitted from Schoenbeck calculation	(403,954)
Adjust: Sumas average to reflect 2.5 years ownership (purchased July 2008).	(317,161)
Recalculation of ICNU Reduction to Rate Year O&M	**(6,466,792)**

Note: Mr. Schoenbeck is proposing averaging both core and major maintenance expense. PSE does not agree with this methodology.

Notes:

(a) - Average O&M less rent expense - 2010 O&M including rent expense.

(b) -Mr. Schoenbeck used a two year average (2009 &2010) $9,438,766/2 = $4,719,383. $4,719,383 - $5,436,912 = ($717,529). Plant was purchased July 2008.

(c) -Omitted from ICNU calculation

(d) -Sumas purchased July 2008, PSE ownership at test year 30 months $11,005,554 /2.5 = $4,402,222.

(e) -Mint Farm purchased in December 2008. This month was not representative of normal operation s and was excluded from calculation.

CROSS-EXAMINATION EXHIBITS OF ICNU – John H. Story			
Story, JHS-33CX	John H. Story	PSE	Excerpt of 2010 BPA Annual Report
Story, JHS-34CX	John H. Story	PSE	Excerpt of REP-12-A-02

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

Exh. No. JHS-33CX
Witness: John H. Story
Page 1 of 13

2010
Annual Report

The Year in Review

IN THE PACIFIC NORTHWEST, EVERY YEAR IS ABOUT WATER.

The region's electric power system is unique. Its largest source of electricity produces no emissions, something almost inconceivable in other parts of the country. The Bonneville Power Administration supplies over a third of the electric power for the Northwest corner of the United States — Washington, Oregon, Idaho and western Montana. Thanks to the federal dams on the Columbia River, BPA's resources are nearly 80 percent[1] hydropower. By comparison, the United States derives just 7 percent of its electricity from hydropower.

Looking to the future, hydropower's value can only increase. It is a clean, non-carbon-emitting renewable that is relatively low cost and — with the exception of Canada — independent of foreign sources of energy. Most recently, hydropower has emerged as a valuable back-up for variable energy output produced by renewable resources such as wind and solar.

But hydropower availability depends on the weather, specifically the region's winter snowpack. A good water year can produce additional generation that is marketed as surplus power, resulting in surplus revenues. These revenues help keep Pacific Northwest electricity rates lower than they might otherwise be. In contrast, a bad water year can mean less surplus power, fewer surplus sales and ultimately lower revenues.

FOOTNOTES CAN BE FOUND ON PAGE 24.

Exh. No. JHS-33CX
Witness: John H. Story
Page 3 of 13

Finance

Fiscal year 2010 was not a good water year. The overall winter snowpack was very low. When the rains finally came in June, they produced a very short, concentrated runoff. In a hydro system, the shape, or timing, of the snowmelt runoff can be even more important than volume. In any event, the overall volume was poor in 2010. The final January–July volume runoff[2] came in at 84.7 million acre-feet, or only 79 percent of the rolling 30-year average.[3] This had a big impact on our revenues for the year.

REMAINING FUNDAMENTALLY SOUND

For fiscal year 2010 the agency had net expenses of $127.6 million based on total operating revenues of $3.06 billion. Modified net expenses were $164.4 million, resulting in a shortfall of $368.4 million against the rate case projection of $204.0 million modified net revenues. Power Services revenue was lower due to low hydro inventory, complicated by low market prices and lower demand from the lagging effects of the economic downturn. Transmission Services provided a bright spot due to higher demand for transmission that included wind energy system integration that offset lower power revenue.

Despite the disappointing revenues for the year, all other signs show that BPA has a solid financial foundation. Our expenses for both power and transmission came in under levels established in our rate case. We made our annual payment for fiscal year 2010 to the U.S. Treasury of $864.1 million. This is significant because it is an important sign that BPA is fully repaying U.S. taxpayers for their investment in the Federal Columbia River Power System. The payment represents principal and interest on the federal investment in the dams, transmission system, fish and wildlife projects and other capital projects.

Over all, agency financial reserves were down, but remain sufficient at $1.11 billion which will help buffer poor water years and any future uncertainties.

The three independent credit-rating agencies — Moody's, Standard & Poor's and Fitch — evaluated BPA's finances and reported BPA's overall financial health is strong. Solid reserves over the last few years put us in a good position to manage through leaner years. Increased borrowing authority made available through the American Recovery and Reinvestment Act has also bolstered BPA's ability to fund capital projects.

WORKING TO MANAGE DEBT

While BPA cannot control how much water comes down the Columbia River or when, there are things we can and do control. One of our most significant costs is our debt service. We have about $13 billion in debt, nearly equally divided between federal and nonfederal debt. This debt funded construction of the federal hydro and transmission systems, one functioning nuclear plant and two nuclear plants that were never finished. BPA's debt obligation for the nuclear plants stems from our contract to pay all plant costs so we can market the power output. Energy Northwest, a consortium of utilities, owns and operates Columbia Generating Station, the region's only commercial operating nuclear plant.

BPA has diligently managed its debt for decades and continues to do so. For example, as part of the Debt Optimization Program we continued to refinance and restructure Energy Northwest debt for other business purposes. As part of this program, BPA worked with Energy Northwest to refinance and extend the maturity date on BPA-backed Energy Northwest bonds. This allowed us to pay back federal debt (bonds and appropriations) earlier than planned.

The program accomplished two things — it reduced overall debt costs and provided BPA with room under its borrowing authority ceiling with the U.S. Treasury. During the course of the program, we restored about $2 billion in available Treasury borrowing authority and reduced the average interest rate on BPA's debt portfolio by 1 percent.

INCLUDING STAKEHOLDERS IN COST REVIEWS

In addition to working actively to control costs, we devoted several months this year to hosting public workshops under an Integrated Program Review that looked ahead to future program spending levels. The review is "integrated" because it examines program levels and costs, both expense and capital, for Transmission Services, Power Services and all supporting agency services.

The goal was to gather input from agency customers and other stakeholders on program levels before the 2012–2013 rate case begins, because changes to program level costs are not considered in a rate case.

An area that could have a large impact on reducing future power rate increases is, not surprisingly, debt service. As it is currently structured, debt service on Energy Northwest debt begins rising in fiscal year 2011 to a peak in 2017 before dropping sharply in 2019. Over the next two fiscal years, Energy Northwest and BPA are taking actions to further restructure some of the Energy Northwest debt. These actions could produce overall annual debt service reductions for the next rate period.

PREPARING FOR RATE SETTING

Because it informs program funding levels, the Integrated Program Review serves as a precursor to the rate-setting process. BPA is a self-funding federal agency that receives no annual appropriations. We must recover our costs through the sales of power and transmission services. The rate cases are the means by which we set the prices for these services.

BPA is preparing to introduce tiered rates for the first time. Last spring we began a series of preliminary rate case workshops in which our staff and interested parties worked toward a common understanding of the details of a new Tiered Rate Methodology. The initial rate proposal for the first rates under this methodology will be issued in November 2010. This will kick off the formal rate-setting process[4] for both Power and Transmission Services.

We expect there will be much to discuss. Often, the most difficult issue in a rate case is balancing tradeoffs between the long and short term. We must balance the need to keep any rate increase as low as prudently possible, especially given current economic conditions, against the need to invest in projects that will keep our system reliable and efficient in the future.

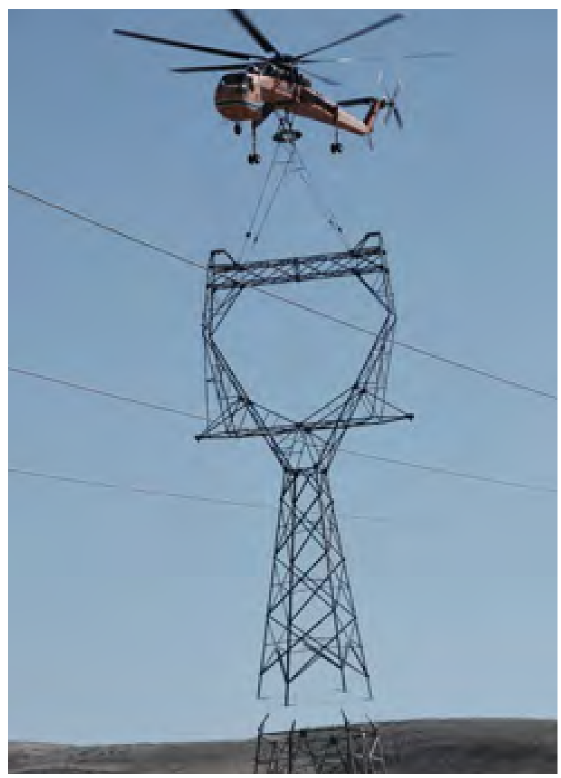
USING ARRA BORROWING AUTHORITY

When Congress passed the American Recovery and Reinvestment Act in 2009, BPA got a welcome boost in its ability to borrow from the U.S. Treasury. The extended borrowing authority was timely, allowing us to make more capital investments[5] in 2010 than in any preceding year. ARRA increased our available Treasury borrowing authority by $3.25 billion. While this is not a grant — BPA will pay taxpayers back with interest for any funds borrowed — it gave us the financial security to move forward with construction of the McNary-John Day transmission project. The line is currently under construction and should be completed in early 2012. Without this additional boost, BPA could have exhausted its remaining borrowing authority as early as 2013.

BPA, the U.S. Department of Energy and the Office of Management and Budget have identified up to $2 billion in projects BPA would fund through the increased borrowing authority. While the McNary-John Day transmission line is the first new line to be constructed using ARRA borrowing authority, we also are looking at using ARRA authority for three more transmission projects as well as hydro system upgrades, energy efficiency initiatives and fish hatchery construction.

In mid-summer, DOE Deputy Secretary Daniel Poneman visited the McNary-John Day line construction site. He had this to say:

"It's impossible to exaggerate the importance of what's happening out here to our nation … BPA's Recovery Act projects will create hundreds of good-paying jobs and help reduce carbon pollution by bringing even more renewable energy to the region. This important investment in the Northwest is an example of the Recovery Act at work — jumpstarting the economy, modernizing the nation's infrastructure, delivering renewable energy and enhancing energy independence."



Department of Energy Deputy Secretary Daniel Poneman, left, and BPA Administrator Steve Wright visited the McNary-John Day transmission line now under construction. At right, a helicopter lifts a tower in place. The line is being built with extended borrowing authority granted under the American Recovery and Reinvestment Act.

Power Services

As Power Services dealt with the operational challenges of the low water year, it also devoted an immense amount of resources preparing to implement the Regional Dialogue power contracts. The contracts are historic due to the introduction of tiered power rates, which are expected to send clearer price signals to encourage customers to develop their own resources thus ensuring the Northwest has adequate resources for the future.

PREPARING FOR NEW LONG-TERM CONTRACTS

New wholesale power sales contracts, signed in December 2008, go into effect Oct. 1, 2011. They will continue through Sept. 30, 2028. A major focus throughout 2010 has been preparing to implement these new and complex contracts, which will introduce tiered rates for the first time. They are known as the Regional Dialogue contracts because of the multi-year discussions with BPA's utility customers and stakeholders that led to their development.

Given their length, the contracts will provide long-term stability at a time when it is sorely needed. Consumer-owned utilities will benefit from certainty about long-term access to federal power, and BPA will have a guaranteed source of revenue that will ensure it can cover its costs and make its Treasury payments.

The contracts also will give the agency and customers far greater certainty while reducing our exposure to volatile power markets. Tiered rates should provide better price signals that reveal the true cost of load growth. There are a number of other benefits. The contracts have been designed to facilitate energy efficiency and the development of renewable power, promote regional resource adequacy and encourage development of electric infrastructure in the Pacific Northwest.

IMPLEMENTING TIERED RATES

Under the Regional Dialogue contracts, consumer-owned utility customers have the right to purchase a certain amount of their firm power at BPA's Tier 1 rates. How much power will be priced at Tier 1 is tied to the relatively low-cost output of the existing federal system. Tier 1 rates will be set to recover costs of the system. Those customers who anticipate growth and need more power than the federal system produces have a choice. They can secure additional power on their own or purchase it from BPA at Tier 2 rates. Tier 2 rates will be set at a level to recover BPA's costs of acquiring the additional power.

For the first two years under the new contracts, our consumer-owned utility customers elected to get about 25 percent of the power they need to serve loads above BPA's existing federal system from BPA.

FINALIZING OUR RESOURCE PROGRAM

After two years of collaborative work with the region and especially with the Northwest Power and Conservation Council,[6] BPA completed its first Resource Program since 1992. The Resource Program analyzes BPA's potential power supply needs and assesses alternatives for meeting those needs in the context of the Council's Sixth Power Plan.

The final Resource Program, released in September, confirms that most of BPA's incremental energy needs for the next several years can be achieved by meeting the conservation targets in the Council's power plan and through short- and mid-term market purchases.

The Resource Program will not determine our resource acquisition decisions. Instead, it provides analytical support and a road map to inform future acquisitions consistent with the Council's Power Plan.

SERVING DIRECT-SERVICE INDUSTRIES

During the year, BPA signed new contracts with two direct-service industrial customers, the Alcoa smelter in Ferndale and Port Townsend Paper Corp., both in Washington state. The contracts have limited terms due to recent decisions by the U.S. Court of Appeals for the Ninth Circuit that non-obligatory contracts with direct-service industries must be consistent with sound business principles. In other words, the benefits to BPA of serving a direct-service industry must equal or exceed BPA's cost of serving the load during the period of service.

We have followed a stringent approach that limits the duration of a sale to these companies based on the perceived costs and benefits of selling them power. We believe these contracts, which run through May 2011, are consistent with the guidance from the court.

In late summer, Alcoa asked for a one-year extension of service under its power sales contract with BPA. We conducted an equivalent benefits test to determine if, and for how long, service under the contract could be extended. We also conducted a public review before a final decision[7] to extend this service, which is expected to help keep the plant open and save about 500 jobs.

DEALING WITH AN ANOMALY

In what otherwise was a very dry year, a series of rainstorms in June dramatically and briefly increased streamflows to 440 percent of normal for the month. Such high streamflows in the Columbia and Snake rivers could lead to nitrogen saturation in the water at levels that cause lethal gas bubble trauma in migrating juvenile salmon. BPA and the Corps operated the hydro system to minimize involuntary spill[8] at the dams, even to the point of asking other generators to shut down their plants and take our hydropower at no cost.

The storms that provided the late spring rain also propelled wind turbines along the Columbia River Gorge. With demand for electricity relatively light at the time, BPA had to devise creative ways to deal with maximum generation from both hydro and wind turbines while limiting spill to safe levels for fish.

The heavy rains could well be a harbinger of operational challenges ahead, particularly as the region's wind fleet continues its rapid growth. We were successful in what was basically a two-week event, but we may not necessarily be successful in the future unless new approaches are developed.

In September, we issued a report containing a factual description of the June event and the operational actions we took. The report is intended to stimulate a regional discussion of mitigation mechanisms that must be developed to prepare for future events.

REVIEWING THE COLUMBIA RIVER TREATY

Since 1964, the Columbia River Treaty has brought benefits to both the United States and Canada by providing a cooperative way to regulate a valuable resource that both countries share — the Columbia River. Under the Treaty, the two nations jointly manage the river for power and flood control.

The U.S. Entity charged with implementing the Treaty is made up of the BPA administrator and the division engineer of the U.S. Army Corps of Engineers' Northwestern Division.[9] Through the Treaty, BPA and Canada have shared benefits of increased downstream energy production. Originally, BPA made a monetary payment to Canada for its half of these benefits for 30 years, but BPA now returns the physical energy back to British Columbia. During fiscal year 2010, as required by the Treaty, BPA oversaw the delivery to the U.S.-Canada border of 4,754,385 megawatt-hours (4.8 terawatt-hours), in amounts up to 1,326 megawatts on any hour, as pre-scheduled by Canada.

Although the Treaty has no termination date, it does have provisions that take effect on and after Sept. 16, 2024. Absent any other action, these provisions will change how flood control is implemented between the two countries, which may affect power benefits as well. In addition to changes in flood control, either the United States or Canada can terminate the Treaty as early as 2024 with a minimum of 10 years' written notice.

To evaluate the possible impacts associated with these provisions, the U.S. and Canadian Entities conducted a series of studies called the Phase 1 Report. This joint effort looked at these provisions from the limited perspective of power and flood control, the two original purposes of the Treaty. The Phase 1 Report was released in July.

To provide additional information, the U.S. Entity conducted further work to evaluate how applying current fish operations might alter the results of the Phase 1 studies. The result was the Supplemental Report, which the U.S. Entity released in September. These reports are the starting point for a multiyear Columbia River Treaty Review process that will engage the region in an open, collaborative process with regard to the future of the Treaty.

In the nearly 50 years since the Treaty was signed, the demands on the Columbia River system have grown beyond just power and flood control. Fish and wildlife concerns as well as water supply and quality, climate change, recreation, irrigation, cultural resources and other river uses have emerged and must be considered.

The U.S. and Canada share the bounty of the Columbia River. A treaty between the two has been in place for nearly 50 years, long before fish and wildlife and other constraints were envisioned. Now a regional discussion has begun about the future of the Treaty.

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Transmission Services

It would be an understatement to say it's been a busy year for BPA's Transmission Services. Indeed, it has been one of the busiest years since the first large transmission lines were built, many of them dating back to the 1940s or earlier. Population growth, greater use of air conditioning and the need to interconnect new renewable resources have all put enormous pressure on an aging system.

BUILDING TO RELIEVE A STRAINED GRID

During the year, Transmission Services has undertaken several critical projects throughout the Pacific Northwest to rebuild transmission lines and substations, replace wood poles and otherwise upgrade aging facilities. These projects are needed to maintain and enhance existing transmission line operations and accommodate new line construction.

But upgrades alone won't meet all the challenges on the grid. To ensure continued reliability and facilitate development of renewable resources, we have proposed a program to construct up to four new 500-kilovolt lines.

One of those lines is well under construction. The 500-kilovolt transmission line known as the McNary-John Day line will run parallel to the Columbia River, crossing the river at one point. The project has created over 100 jobs. When energized, it will allow BPA to provide transmission service for nearly 700 megawatts of new wind energy. It is currently ahead of schedule and expected to be completed in early 2012.

Three more 500-kilovolt lines have been proposed and are undergoing public and environmental review. These include the proposed I-5 Corridor Reinforcement Project that would serve southwest Washington and the metropolitan Portland, Ore., area. Approximately 80 percent of the power flowing through this line would serve local needs. No new line has been built in the area in 40 years. During that time, the population has doubled. We continue to meet with local citizens and carefully consider their views on a range of options for placement of the line and a new substation.

The other two proposed 500-kilovolt lines include the Big Eddy-Knight Transmission

Project in south central Washington and north central Oregon and the Central Ferry-Lower Monumental Transmission Project in eastern Washington state. Draft environmental impact statements have been released for both projects. We anticipate records of decision in spring 2011.

PUSHING FOR A SMARTER GRID

Even as we explore expansion of our transmission grid, we also are working on improving the existing system. One of those ways is through a “smarter” grid, one in which even consumers might interact electronically with the system to use electricity at times when demand and prices are lower. A smart grid also would help integrate variable renewable resources such as wind.

We are supporting two major projects partially funded through the American Recovery and Reinvestment Act — the Pacific Northwest Smart Grid Demonstration Project and the Western Interconnection Synchrophasor Program. In addition, we are leading several smart grid research and pilot projects to explore how different smart grid technologies can benefit BPA’s customers through cost containment and improved reliability.

The Pacific Northwest Smart Grid Demonstration Project, directed by the Battelle Memorial Institute, Pacific Northwest Division, in Richland, Wash., includes a number of partners across five states and is expected to involve more than 60,000 metered customers. BPA is contributing $10 million to the five-year project.

It will measure and validate smart grid costs and benefits for consumers, utilities, regulatory bodies and the nation. Results will inform business cases for future smart grid investments so utilities can select the most cost-effective technologies for their customers. Project participants will use and test a variety of smart grid technologies such as smart appliances, smart meters, distributed generation, in-home displays, home area networks, voltage optimization tools and electric vehicles. The project also will explore ways to improve the integration of renewable energy resources such as solar and wind. Among other things, we will be coordinating with Battelle to create a regional business case for smart grid technologies.

The Western Interconnection Synchrophasor Program deals with synchrophasor measurements, a type of smart grid technology that can help keep the grid stable and enhance reliability. This technology establishes a virtual firewall between generation and transmission to protect equipment. It uses an extensive communication network to help prevent the kind of grid instabilities that can occur when the system gets out of phase. BPA is one of the first transmission operators to use this technology.

Smart grid technologies hold great potential to improve transmission reliability and reduce the need for new transmission infrastructure and power resources.

COMPLYING WITH RELIABILITY STANDARDS

Achieving and sustaining compliance with new reliability standards is a major undertaking for the entire utility industry, including BPA. Given the magnitude of these changes, the North American Electric Reliability Corp. allowed utilities to phase in compliance requirements between 2008 and 2010.

BPA achieved a significant milestone in June by demonstrating compliance with a series of regulatory standards known as NERC CIP. CIP stands for critical infrastructure protection. We are complying with all auditable NERC CIP Standards.

We upgraded security measures at substations across the region. These measures include tighter access procedures and controls as well as other physical security monitoring devices and equipment.

In a separate effort, BPA is complying with the Department of Energy’s Graded Security Protection Policy that outlines what BPA must do to protect its critical assets. While NERC CIP standards address security measures to protect

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key information technology assets, the DOE security policy focuses more on substation yards and cyber technology equipment.

CONDUCTING NETWORK OPEN SEASON

For the third year in a row, we have conducted a Network Open Season, a process that enables us to better manage the numerous transmission requests that come to us. The open season allows us to set priorities for financing and building new transmission projects and, equally important, to determine which requests can be met with current transmission. Because requests can be evaluated in a "cluster," we are better able to study the interactions among these requests.

This year, we received 76 signed agreements and financial commitments for over 3,700 megawatts of new transmission service. Of that amount, almost 2,500 megawatts would be for wind generation. Since Network Open Seasons were introduced in 2008, we have 263 signed agreements to purchase 11,722 megawatts of transmission capacity. Not all these requests will require new transmission. We also have focused on reducing congestion on existing lines, so capacity can be freed up.

Top: Linemen bolt the top of a banjo tower to its base on the McNary-John Day transmission project. Below: Miles of recently completed towers await stringing with conductor.

RENEWING COLUMBIAGRID AGREEMENT

In July, BPA signed a six-year general funding agreement for its continuing membership and participation in ColumbiaGrid,[10] a regional transmission planning and services organization. The agreement affirms our support for ColumbiaGrid's participation in broader regional transmission efforts.

These efforts include joint projects, studies of the benefits of utility balancing authority[11] area consolidation and exploration of a regionwide open season for transmission requests. These efforts are central to the region's efforts to integrate large amounts of new renewable resources cost effectively.

Most ColumbiaGrid costs are recovered through services it provides under functional agreements on regional transmission planning and expansion and development of a common OASIS[12] portal and transmission services. The new 2010 ColumbiaGrid funding agreement will remain in effect through Dec. 31, 2016.

Wind

The act of integrating massive quantities of wind into our system while maintaining reliability has been described as thrilling, exciting and scary all at the same time. It is all of those things. Demand for clean, renewable electricity continues to drive wind power development in the Pacific Northwest, and BPA's aggressive and often innovative initiatives are helping make BPA a national leader in facilitating wind development.

HELPING WIND GROW RAPIDLY

The growth rate of wind interconnections on our transmission system has been astounding. In 2009 the amount of wind integrated into our transmission system went from 1,500 megawatts to more than 2,500 megawatts. It is now slightly over 3,000 megawatts, and we expect it to reach 6,000 megawatts by 2013.

The challenge in integrating a variable and hard-to-predict resource into a transmission grid is largely a matter of physics. To keep the grid stable, electric generation must exactly match consumption in real time. When actual wind generation varies from scheduled generation, BPA must immediately increase or curtail other generation to maintain electric system reliability.

Realizing the tremendous value of clean renewable resources to both our region and the nation, we have undertaken this challenge. Often, it has meant inventing new technologies and developing new protocols where none existed before.

MEETING WIND'S CHALLENGES

The Columbia River hydro system has served as a "zero emission storage battery" for the variable output of wind generation, but the capability of the hydro system has its limits. BPA teams are now engaged in three categories of actions to meet the challenge of integrating more wind generation while maintaining system reliability. These actions are increasing transmission capacity, providing more reliability services from the existing system and exploring new resources that could provide additional capacity and flexibility.

The day is rapidly approaching, however, when we are likely to have wrung all of the efficiencies we can from the existing system and will need new tools to provide balancing services for

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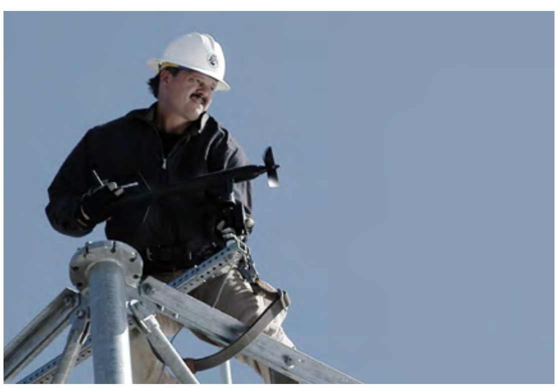
variable renewable resources. We are working with the Pacific Northwest National Laboratories on a study of energy storage options that could absorb excess wind energy in periods of low demand and return it during periods of greater demand. We also are evaluating enhancing the John W. Keys Pump Generating Plant near Grand Coulee Dam to see if it can provide further capacity and flexibility to accommodate more wind by providing storage for reserves.

Until now, wind power projects located in our transmission balancing authority have relied entirely on federal hydropower to compensate for unscheduled swings in wind output. BPA now reserves significant portions of federal hydro capacity to provide this service. On Sept.1, we launched two new pilot projects, one with Iberdrola Renewables and one with Calpine Corp., to test approaches to lessen the dependence on hydro reserves.



A Transmission Services employee adjusts the angle of a new anemometer, one of 14 in BPA's wind forecasting fleet. It's located atop BPA's microwave station at Sunnyside, Wash. The anemometers measure wind speed and direction, temperature, humidity and barometric pressure.

FINDING NEW WAYS TO FACILITATE WIND POWER

We, along with the rest of the wind community in the Pacific Northwest, have been on a steep learning curve to support new renewable generation. We intend to stay focused on actions that support carbon-free resources. In 2010 we introduced new transmission operating rules designed to ensure we can operate the system reliably through variations in wind output. Our dispatchers began using a new wind operations screen, which gives them a real-time picture of what each wind project is doing and how much of our generation reserves is being used.

We are exploring dynamic transfer, which allows a utility to remotely control and manage a power plant in another utility's balancing authority. We are working with regional wind developers to more accurately predict when and where the wind will blow and at what speed. BPA is now harvesting information from 14 anemometers specifically designed to help forecast wind activity.

For the first time this year, wind farms are using BPA's new intra-hour system that allows wind projects to sell excess power on the half-hour, rather than the hour. That step, and the flexibility it brought, is delivering more wind power to regional customers and easing pressure on the power system.

And, for the first time, BPA has connected nonfederal generation — three wind plants — to our automated generation control system. This connection allows us to manage deviations of wind power from its scheduled production. This is an exciting step forward. It demonstrates our ability to partner with nonfederal generation, and it opens up a realm of potential new tools for keeping the system reliable.

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Residential Exchange Program Settlement Agreement Proceeding (REP-12)

ADMINISTRATOR'S FINAL RECORD OF DECISION

July 2011

REP-12-A-02

STATEMENT OF THE ADMINISTRATOR

It has been over a decade since BPA last considered a settlement of the Residential Exchange Program (REP) established by section 5(c) of the Northwest Power Act. As most of those reading this Record of Decision will be aware, BPA's previous attempt at resolving the REP was not broadly supported in the region and resulted in the filing of numerous lawsuits with the United States Court of Appeals for the Ninth Circuit. The history of the ensuing litigation and the various proceedings and hearings that BPA conducted in response to the Court rulings will be described in greater detail in this Record of Decision. Suffice it to say, no other statutory provision of the Northwest Power Act has engendered more litigation and contentiousness than the REP, with 56 petitions for review now pending before the Court. As we have worked through these issues over the various proceedings, I can state with certainty that I have spent countless hours and have dedicated dozens of agency staff to considering the parties' respective and, often, completely divergent views on the proper implementation and rate treatment of the REP.

In 2008, as I was making my final findings in the most controversial of the REP records of decision, I took the unprecedented step of addressing the region in a personal statement. In that statement, I appealed to the litigating parties to find a path that would avoid embroiling the region in perpetual litigation and uncertainty over BPA's rates and the REP. At the end of my statement, I called on the parties to work together to find another lawful way:

> This has been a very difficult undertaking, fraught with complexity and with large financial stakes. I believe we have done the best we could do to find a legally sustainable and politically equitable solution (in that order) to the challenge provided by the Ninth Circuit. Nevertheless, I would suggest there remains considerable uncertainty for the parties as to how REP issues may evolve in the future. For that reason I continue to urge the parties to work towards a lawful settlement that will provide greater long-term certainty and, because it will be defined by the parties, greater political equity than what any single Administrator, acting within the confines of the law, can provide.

See 2007 Supplemental Wholesale Power Rate Case, Administrator's Final Record of Decision (WP-07 Supplemental ROD), WP-07-A-05, at xx-xxi.

In response to this call, the parties have answered with the 2012 Residential Exchange Program Settlement. I will leave it to the balance of this Record of Decision to discuss my findings on the legal, factual, and policy merits of the Settlement. Here, however, I would like to express my gratitude to the parties for their dedication and collaboration in providing an alternative to the contentious legal challenges that have come to define the REP. The fact that the Settlement is supported by all six regional investor-owned utilities (IOUs), consumer-owned utilities (COUs) representing 88.1 percent of BPA's load, three state utility commissions, a number of COU representative groups, and a retail ratepayer advocacy group, who no more than a year and a half ago were locked in an epic legal battle before the Court over the REP, is a testament to the diligence, commitment, and excellent work of the negotiating parties. Together, this coalition of interests represents entities that serve roughly 93 percent of the load in the Pacific Northwest region. I commend the negotiating parties for the enormous effort they put into the Settlement to achieve this level of support. I want to thank all of those involved for your hard work and perseverance through difficult and lengthy negotiations. The region is well-served due to your efforts.

2000–2001 caused BPA to revise its rates and the 2000 REP Settlement benefits. The payments to the IOUs were increased because the 2000 REP Settlements set REP benefits as the difference between the market price of energy and BPA's then-PF Preference rate; thus, as the West Coast energy crisis drove market prices upward, REP benefits increased. Also, BPA entered into Load Reduction Agreements (LRAs) during the energy crisis with two IOUs that allowed BPA to monetize the expected power sales to these utilities. In all, the modifications increased the 2000 REP Settlement benefits by more than $160 million per year, resulting in over $300 million in total benefits paid each year during FY 2002–2006. Most of these costs fell on BPA's preference customers and their consumers.

1.3.4 Challenges to the 2000 REP Settlements and the WP-02 Rates

In January of 2001, certain parties filed petitions with the Ninth Circuit challenging BPA's statutory authority to implement the REP through the 2000 REP Settlements. In September 2003, following final FERC confirmation and approval of BPA's WP-02 rates, parties also filed challenges to BPA's decision to recover the costs of the 2000 REP Settlements from the PF Preference rate without performing the 7(b)(2) rate test.

In 2003, BPA proposed a settlement of all legal challenges to the 2000 REP Settlements and other litigation. This "global" settlement was never adopted. Nevertheless, based on the proposed global settlement and on BPA's posting of the PacifiCorp and Puget Sound Energy LRAs on its Web site, two parties challenged a provision of the LRAs (referred to as the "Reduction in Risk" provision) under which the cost of the two LRAs decreased if all parties settled the 2000 REP Settlement litigation.

After the global settlement efforts failed, BPA and the IOUs executed a number of amendments to the 2000 REP Settlements in 2004 that placed caps and floors on the amount of payments the IOUs would receive during FY 2007–2011. These amendments are referred to as the 2004 Amendments. Among other changes effectuated by the 2004 Amendments was an amendment to the Reduction in Risk provision that deferred the payment of $100 million under the LRAs until the FY 2007–2011 period. The 2004 Amendments were timely challenged.

In 2006, while all of the foregoing challenges were still pending before the Court, the WP-02 rates expired and were replaced by rates established in BPA's 2007 Wholesale Power Rate Proceeding (WP-07 rates) for the FY 2007–2009 period. In setting the WP-07 rates, BPA again allocated a significant portion of the costs of the 2000 REP Settlements to the PF rate without performing the 7(b)(2) rate test. The WP-07 rates were filed with FERC on July 28, 2006, and received interim approval from the Commission on September 21, 2006.

1.3.5 The Court's Decisions: *PGE*, *Golden NW*, and *Snohomish*

On May 3, 2007, before FERC approved BPA's WP-07 rates, the Court issued two decisions in the pending challenges to the 2000 REP Settlements and the then-expired WP-02 rates. In *Portland General Electric v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) (*PGE*), the Court granted petitions challenging BPA's decision to adopt the 2000 REP Settlements. Significantly, the Court concluded that the 2000 REP Settlements were an improper exercise of

BPA's settlement authority because they were inconsistent with sections 5(c) and 7(b) of the Northwest Power Act.

In a companion case issued the same day, *Golden Northwest Aluminum v. Bonneville Power Admin*., 501 F.3d 1037 (9th Cir. 2007) (*Golden NW*), the Court held that BPA had improperly allocated the cost of the 2000 REP Settlements to the then-PF Preference rate in violation of section 7(b)(2). 501 F.3d at 1048. The Court concluded it was not proper for BPA to allocate to the PF Preference rate costs of the 2000 REP Settlements in excess of the section 7(b)(2) rate test trigger amount based on BPA's theory that such costs were incurred pursuant to the Administrator's section 2(f) contracting authority and could therefore be "equitably allocated" pursuant to section 7(g) of the Northwest Power Act. The Court remanded the WP-02 rates to BPA with instructions to set rates "in accordance with this opinion." *Id*. at 1053.

After issuing the *PGE* and *Golden NW* decisions, the Court also reviewed challenges to certain amendments to the 2000 REP Settlements signed in 2004. *See Pub. Util. No. 1. of Snohomish County, Wash. v. Bonneville Power Admin*., 506 F.3d 1145 (9th Cir. 2007) (*Snohomish*). In *Snohomish*, the Court held that the validity of the 2004 Amendments depended on how BPA treated the underlying 2000 REP Settlements in light of *PGE*. *Id*. at 1154. The Court then remanded to BPA the 2004 Amendments and the Reduction of Risk portion of the LRAs (as amended by the 2004 Amendments). *Id*. The Court dismissed all other challenges to the LRAs. *See Pub. Util. Dist. No. 1 of Grays Harbor County, Wash*., 250 Fed. Appx. 820; *Pub. Util. Dist. No. 1. of Snohomish County, Wash*., 250 Fed. Appx. 817; *Pub. Util. Dist. No. 1 of Snohomish County, Wash*., 250 Fed. Appx. 821.

1.3.6 BPA's Response to *PGE*, *Golden NW*, and *Snohomish*: the WP-07 Supplemental Rate Hearing (FY 2002–2009) and the 2008 RPSAs

1.3.6.1 Overview of the WP-07 Supplemental Rate Hearing

Following the issuance of the *PGE*, *Golden NW*, and *Snohomish* decisions, BPA ceased making payments to the IOUs under the 2000 REP Settlements and commenced a section 7(i) process to determine whether and to what extent the 2000 REP Settlements caused illegal costs to be included in rates charged to the COUs. This proceeding, referred to as the WP-07 Supplemental Rate Hearing, began in February of 2008. The WP-07 Supplemental proceeding had three central components.

First, BPA established rates for FY 2009 that complied with the Court's order by removing the costs of the 2000 REP Settlements and replacing them with the costs of REP benefits that complied with sections 5(c) and 7(b)(2) of the Northwest Power Act. As part of BPA's prospective implementation of the section 7(b)(2) rate test, BPA revised its Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology.

Second, BPA performed an analysis, referred to as the "Lookback," to determine whether BPA had overcharged the COUs' rates for the WP-02 period (FY 2002–2006) and the first two years of the WP-07 rate period (*i.e.*, FY 2007–2008) (collectively, the "Lookback period"). To do this, BPA compared the payments the IOUs received under the 2000 REP Settlements with the amount of REP benefits the IOUs would have received under a traditional implementation of the REP pursuant to sections 5(c) and 7(b) of the Act. To calculate the amount of REP costs for the Lookback period, BPA reviewed how ASCs would have been established during the Lookback period under the 1984 ASC Methodology, how BPA would have included REP costs in the WP-02 and WP-07 rates, and any adjustments that would have been necessary to more closely track the amount of REP benefits that would have been incurred during that period through implementation of the REP in the absence of the 2000 REP Settlements. Accordingly, BPA made a number of adjustments to its calculation of the section 7(b)(2) rate test, adjustments that would have been incorporated into the WP-02 and WP-07 rates in the absence of the 2000 REP Settlements using information available when establishing the final WP-02 and WP-07 rates.

Third, BPA proposed a method for collecting the overcharges from the IOUs and returning these funds to the COUs as refunds. IOUs that received more in REP benefits under the 2000 REP Settlements than allowed by sections 5(c) and 7(b)(2) of the Northwest Power Act would be assessed a refund obligation known as a "Lookback Amount." BPA proposed to collect the Lookback Amounts from the IOUs by withholding future benefits owed to the IOUs under the REP. The withheld REP benefits would then be used to fund refunds to the injured COUs that were originally overcharged in rates as a result of the 2000 REP Settlements.

1.3.6.2 Conclusions Reached in the WP-07 Supplemental Rate Hearing: the WP-07 Supplemental Record of Decision (WP-07 Supplemental ROD)

The WP-07 Supplemental Rate Hearing proved to be one of the most complex administrative hearings conducted in BPA's history. By the close of the eight-month WP-07 Supplemental Rate Hearing, BPA had compiled an administrative record that exceeded 117,000 pages. The parties raised hundreds of issues regarding BPA's Lookback Analysis and implementation of the section 7(b)(2) rate test. BPA responded to the parties' arguments in a 709-page ROD, the 2007 Supplemental Wholesale Power Rate Case Administrator's Final Record of Decision (WP-07 Supplemental ROD), issued on September 22, 2008. WP-07 Supplemental ROD, WP-07-A-05.

In the WP-07 Supplemental ROD, BPA concluded that the COUs had been overcharged in rates as a result of the 2000 REP Settlements by approximately $1 billion during the FY 2002–2008 period. *Id*. at 166-251. BPA proposed to return these overcharges to the injured COUs with an initial lump-sum cash payment in 2008 and then through future reductions in REP benefit payments to the applicable IOUs. *Id*. at 256-297.

In addition to determining the refunds and overcharges caused by the 2000 REP Settlements, the WP-07 Supplemental ROD also addressed BPA's final decisions on the appropriate amount of REP benefits to pay the IOUs and include in rates for FY 2009. To make this determination, BPA had to address a host of controversial issues related to the section 7(b)(2) rate test. More than 270 pages of the WP-07 Supplemental ROD were dedicated to addressing the issues and arguments presented by the parties on the section 7(b)(2) rate test alone. *Id*. at 398-676.

The extraordinary complexity of the issues in the WP-07 Supplemental Rate Hearing led BPA's Administrator, Stephen Wright, to take the unprecedented step of issuing a statement as a preface to the WP-07 Supplemental ROD. In this statement, Administrator Wright candidly acknowledged that "[o]f the three BPA power rate cases I have had the responsibility for deciding, all have been contentious, but this has been by far the most difficult." WP-07 Supplemental ROD, WP-07-A-05, at xv. While including the "usual array of complex issues associated with projected revenues, rate design, and rate levels," this case also involved the "unprecedented challenge of responding to a remand from the Ninth Circuit Court of Appeals." *Id*. The complexity present in this proceeding was compounded by the substantial debate over BPA's implementation of section 7(b)(2) of the Northwest Power Act, a provision that Administrator Wright described as a "[b]yzantine sentence that nearly fills a page and that is, in my view, the most complicated section in the Act." *Id*.

1.3.6.3 Development of the 2008 RPSAs

Because the traditional REP was being implemented for FY 2009, BPA also needed to negotiate and execute new RPSAs with the IOUs intending to participate in the REP. Thus, concurrent with the WP-07 Supplemental Rate Hearing, BPA engaged in a public process to develop new RPSAs. After taking public comments on a prototype RPSA, BPA published a final RPSA in September of 2008. Among other terms included in the RPSA, BPA adopted a provision that would allow BPA to recover the Lookback Amounts from the IOUs by reducing future REP benefit payments. BPA's justification for including this and other provisions in the RPSA was explained in the 2008 RPSA Record of Decision (2008 RPSA ROD).

1.3.7 Challenges to the WP-07 Supplemental ROD and the 2008 RPSA ROD: *APAC*, *IPUC*, and *Avista*

BPA's decisions in the WP-07 Supplemental ROD and the 2008 RPSA ROD were vigorously opposed by both COUs and IOUs, state utility commissions from Oregon (OPUC) and Idaho (IPUC), and the Citizens' Utility Board of Oregon (CUB). Although the parties' claims are numerous and multifaceted, they can generally be summarized as follows: the COUs claim that BPA has grossly underestimated the IOUs' refund obligation and that the actual overcharge to COUs for the FY 2002–2008 period is at least $2 billion and growing. The IOUs, in contrast, argue that no refunds are owed at all because the Court did not direct BPA to provide refunds and because the terms of their 2000 REP Settlements specifically prohibit BPA from recouping REP benefits paid under those agreements.

The IOUs and the COUs also oppose BPA's interpretation and implementation of the section 7(b)(2) rate test. These disputes, if resolved in the manner advocated by the IOUs, would eliminate the triggering of the section 7(b)(2) rate test, thereby reducing the PF Exchange rate, and as a result substantially increasing the IOUs' REP benefits. Conversely, if resolved in the manner advocated by the non-exchanging COUs, these issues would result in a larger triggering of the section 7(b)(2) rate test, thereby increasing the PF Exchange rate, and as a result substantially decreasing the IOUs' REP benefits.

In the months following BPA's issuance of the WP-07 Supplemental ROD and the 2008 RPSA ROD, the parties filed multiple petitions for review with the Ninth Circuit. These petitions were subsequently consolidated into the following three cases.

1.3.7.1 *Ass'n of Public Agency Customers et al. v. Bonneville Power Admin.*, Nos. 08-74725 *et al.* (*APAC*)

Following the WP-07 Supplemental proceeding, BPA issued its WP-07 Supplemental ROD on September 22, 2008. In the WP-07 Supplemental ROD, as noted above, BPA conducted its comprehensive "Lookback" analysis wherein BPA calculated the refunds owed to the COUs and the refund liability of each of the IOUs. Beginning November 14, 2008, various BPA customers and constituents filed 14 petitions for review with the Ninth Circuit challenging BPA's Lookback analysis and the refund-related findings BPA reached in the WP-07 Supplemental ROD. On January 20, 2009, the Court issued an order consolidating all the petitions for review into *APAC* and granting interventions. Briefing on the issues in these cases concluded in March 2010.

1.3.7.2 *Idaho Public Utilities Comm'n et al. v. Bonneville Power Admin.*, Nos. 08-74927 *et al.* (*IPUC*)

Beginning December 3, 2008, certain BPA customers and state public utility commissions filed seven petitions for review with the Ninth Circuit challenging the 2008 RPSAs, which were offered to customers eligible for the REP on September 12, 2008. Shortly thereafter, six other petitions for review were filed by various BPA customers and constituents seeking review of the same or substantially the same actions. These parties challenge various provisions of the RPSA. In particular, the petitioners object to a provision of the RPSA that permits BPA to withhold REP benefits payable to the IOUs in order to recover Lookback Amounts determined in the WP-07 Supplemental ROD. On January 16, 2009, the Court issued an order consolidating all the petitions for review into *IPUC* and granting interventions. Briefing on the issues in these cases concluded in March 2010.

1.3.7.3 *Avista Corp. et al. v. Bonneville Power Admin.*, Nos. 09-73160 *et al.* (*Avista*)

On July 16, 2009, FERC granted final approval to BPA's WP-07 Wholesale Power Rates. Within the next 90 days, a number of parties filed petitions for review with the Ninth Circuit challenging BPA's WP-07 rates, BPA's 2008 Section 7(b)(2) Legal Interpretation, and BPA's Section 7(b)(2) Implementation Methodology. These consolidated petitions involve challenges to BPA's WP-07 ratemaking issues and in particular the 7(b)(2) rate test decisions BPA reached in the WP-07 Supplemental ROD. Briefing on these issues will commence in September 2011.

1.3.8 The Second Generation of Challenges—The WP-10 Record of Decision: *PGE II* and *PacifiCorp*

While the *APAC* and *IPUC* cases were being briefed, BPA commenced a rate proceeding to establish rates for the FY 2010–2011 period (WP-10 rate proceeding). In the WP-10 rate proceeding, BPA proposed to continue to implement the Lookback remedy by reducing the

IOUs' prospective REP benefit payments and paying refunds to the COUs based on the determinations made in the WP-07 Supplemental ROD. BPA also proposed to implement the section 7(b)(2) rate test in the same manner as in the WP-07 Supplemental ROD. In order to minimize the need for BPA and the parties to file duplicative arguments addressed in the WP-07 Supplemental ROD, all of the parties' arguments and evidence submitted in the WP-07 Supplemental Rate Hearing related to the Lookback and BPA's implementation of sections 7(b)(2) and (3) were incorporated by reference into the WP-10 administrative record.

On July 21, 2009, BPA issued its final Record of Decision in the WP-10 rate proceeding (WP-10 ROD). Subsequently, parties filed petitions challenging BPA's decisions in the WP-10 ROD. These challenges were consolidated by the Court as described below.

1.3.8.1 *Portland General Electric Co. et al. v. Bonneville Power Admin.*, Nos. 09-73288 *et al.* (*PGE II*)

On July 21, 2009, BPA issued its final decision in the WP-10 rate proceeding. As noted above, the WP-10 rate proceeding incorporated certain decisions from BPA's WP-07 Supplemental ROD that are under review in *APAC*. In October and November of 2009, five investor-owned utilities filed petitions for review of such decisions to the extent the decisions involved non-ratemaking issues that might be subject to the Ninth Circuit's jurisdiction prior to FERC's final approval of BPA's WP-10 power rates. It is BPA's understanding that these challenges are primarily directed at BPA's decision to withhold REP benefits from the IOUs in order to repay the disputed Lookback Amounts. The IOU petitioners in *PGE II* acknowledge that the ratemaking issues in the WP-10 rate case (such as the implementation of sections 7(b)(2) and (3)) would not be timely until FERC granted final confirmation and approval to such rates. Briefing on these issues is scheduled to commence in December of 2011.

1.3.8.2 *PacifiCorp et al. v. Bonneville Power Admin.*, Nos. 10-73348 *et al.*

On August 6, 2010, FERC granted final confirmation and approval of the WP-10 power and transmission rates. Certain investor-owned utilities, consumer-owned utilities, and a group of industrial consumers served by consumer-owned utilities filed petitions for review of the Lookback and ratemaking decisions underlying the WP-10 rates. These consolidated petitions for review were in turn consolidated with the petitions for review in *PGE II*, Nos. 09-73288 *et al*.

1.4 The Need for Settlement of the REP Litigation

As summarized above, there is extensive litigation pending in the Ninth Circuit on issues related to BPA's establishment of its power rates and BPA's implementation of the REP from FY 2002 to the present. By the release date of this ROD, there are 56 petitions before the Ninth Circuit challenging virtually every aspect of BPA's Lookback and section 7(b)(2) decisions. Stiffler *et al.*, REP-12-E-BPA-13, at 4; *see also* Murphy and Kallstrom, REP-12-E-JP02-02, at 3. This litigation creates significant uncertainty for BPA and its customers regarding both retrospective and prospective wholesale power rate levels and REP benefits. Furthermore, the scope of these challenges spans a decade of BPA ratemaking, from FY 2002–2011. Stiffler *et al.*, REP-12-E-

BPA-13, at 4. A remand by the Court of a substantive issue in any of the pending Ninth Circuit cases could result in BPA having to once again revise rates from prior periods to conform to the Court's opinion. *Id.*

The disruption that the pending litigation poses to BPA and the region is substantial. As things stand now, not a single COU or IOU ratepayer of BPA knows whether or not the rates it has paid, the REP benefits it has distributed to its consumers, or the refunds it has received over the past 10 years are lawful. *Id.* To put this in perspective, by the end of FY 2011, BPA will have paid $587 million in refund payments to the COUs and $637 million in REP benefits to the IOUs during FY 2007–2011. FY 2012–2013 Lookback Recovery and Return Study, REP-12-E-BPA-03, at 6, 16, line 76 (sum of columns D, E, and F plus $110.4 million paid to IOUs pursuant to the 2008 Residential Exchange Interim Relief and Standstill Agreements). *Every single one of these dollars is potentially subject to being reclaimed by BPA as a result of the pending REP litigation.* Furthermore, as noted by Staff, "the problem only grows with time." Stiffler *et al.*, REP-12-E-BPA-13, at 4. To date, the IOUs, OPUC, IPUC, CUB, and the Washington Utilities and Transportation Commission (WUTC) contend that all of the $587 million in withheld REP benefits must be paid to their regional consumers. Conversely, the COU-aligned parties claim the unpaid refund amounts still owed by the IOUs have ballooned to "$4.028 billion, and [are] increasing." Wolverton, REP-12-E-AP-01, at 14. With each new attempt by BPA to "fix" the latest set of problems with its implementation of the REP, a new wave of litigation will likely be filed. Stiffler *et al.*, REP-12-E-BPA-13, at 4. The end result is that, until the Court finally rules on almost every issue in contention among the many parties, the region will face continuing uncertainty in both the level of the PF rate and the amount of REP benefits payable to the IOUs. *Id.* at 5. As Staff ominously noted: "We are already in the second generation of litigation; how many more generations need to occur before matters are finally consummated? We fear that this generation would not be the last." *Id.*

This fear of never-ending litigation over the REP was echoed by other parties and served as one of the primary motivations behind the movement among COUs and IOUs to seek an alternative to litigation. In considering their reasons for moving away from litigation, a large group of COUs responded as follows:

> The prospect for never-ending, inconclusive litigation caused most of [the Settling COUs to] recognize the unlikelihood of achieving any certainty through litigation and remand in a time frame they considered reasonable. And, increasingly, parties have realized that a small minority of the parties affected by the costs or benefits of the REP could embroil everyone else through a seemingly endless cycle of conflict and related expense.

Murphy and Kallstrom, REP-12-E-JP02-02, at 18-19.

Resolution of past disputes was not the only reason parties so diligently sought an alternative to continued litigation over the REP. With the regional IOUs and COUs at loggerheads over BPA's implementation of the REP, the long-term needs of the region also suffered. As described by one set of customers:

> The uncertainty over the costs of the REP complicates any long-term planning by COUs, including resource planning. The uncertainty also affects the COUs' long-term management of rates, because one major cost component of their most significant power source is unpredictable. The time-lags created by fighting the issues out in rate cases before BPA and then challenging BPA's determinations in court also create potential inequities because of the practical inability to get any relief into the hands of whichever retail consumers may have been harmed. These numerous and significant uncertainties are among the major factors that have encouraged the COUs to attempt to develop a settlement with BPA and the IOUs that addresses both the pending litigation and the future REP costs.

Id. at 14. Whereas continuing to litigate the REP could, at best, result in "additional litigation, forcing the parties to repeat the cycle," a settlement offered the litigating parties a "reliable route to known, acceptable results within a reasonable time frame." *Id*. at 13, 20.

The time for settlement of the REP was also particularly ripe because of new developments in BPA ratemaking. The FY 2012–2013 rate period is the inaugural rate period under BPA's Tiered Rate Methodology (TRM), which serves as the rate methodology BPA will use to set rates for BPA's COU customers under their 17-year Regional Dialogue Contracts. Carrasco *et al.*, REP-12-E-JP02-01, at 4. As described by one group of COU representatives, "[t]he TRM and the 'Regional Dialogue' contracts related to the TRM represent a fundamentally new, more stable model for BPA to conduct its power marketing business." *Id*. In the context of a new set of long-term power contracts and a new rate methodology, these COUs contend that it "makes sense for BPA, the IOUs, and the COUs to concurrently develop an agreed-upon long-term, stable model for implementing the REP." *Id*.

It is against this factual backdrop that regional parties turned their attention from litigation to settlement discussions. These discussions took place over a number of years in various forums and venues. A brief description of these efforts is provided in the next section.

1.5 Background of the 2012 REP Settlement

1.5.1 Pre-WP-07 Supplemental ROD Efforts at Settlement—the November 2007 Recommendations

The 2012 REP Settlement reflects the efforts of a broad group of BPA customers and other interested parties that, for the better part of four years, has attempted to reach a global settlement of disputes over BPA's past and future implementation of the REP. Evaluation Study, REP-12-FS-BPA-01, section 4.1. These efforts began in mid-2007, shortly after the Court issued its decisions in *PGE* and *Golden NW*. *Id*. At that time, BPA commenced a series of meetings with interested parties to discuss BPA's response to the Court's opinions. *Id*. During these meetings, BPA encouraged representatives of the COUs and IOUs to reach a settlement over the REP to avoid protracted and complicated litigation. *Id*. Thereafter, a group of IOU and COU representatives, representing the vast majority of regional utilities, engaged in an intensive negotiation effort to find common ground. *Id*. Ultimately, in November 2007, the represented parties were able to reach agreement on a non-binding value structure and framework that, in the parties' view, would equitably resolve both past and future disputes over BPA's implementation of the REP. *Id*. These recommendations, referred to as the November 2007 Recommendations (Recommendations), asked BPA, among other items, to reinstate the REP with the expectation of providing the IOUs between $200 million and $220 million annually (in nominal dollars) from FY 2007 through FY 2028. *Id*.; *see also* Bliven *et al*., WP-07-E-BPA-52, at 26-27. The parties requested that BPA implement the Recommendations in its WP-07 Supplemental rate proposal. *Id*.

The parties submitted the Recommendations to BPA just prior to the scheduled initiation of BPA's WP-07 Supplemental rate proceeding. *Id*. In response, BPA delayed the commencement of the WP-07 Supplemental rate proceeding and met with IOU and COU groups throughout November and December 2007 in an attempt to determine whether the concepts in the Recommendations could feasibly be implemented. *Id*. Although progress was being made on developing a construct that would permit Staff to propose an implementation of the Recommendations in rates, time constraints ultimately precluded the parties and Staff from finalizing a resolution that could be proposed in the WP-07 Supplemental rate proceeding. *Id*. at 27-28. Staff subsequently withdrew from the settlement discussions to focus on completing the initial proposal for the WP-07 Supplemental proceeding. *Id*. at 28. Although some aspects of the Recommendations were considered in developing the initial proposal, Staff was unable to implement in the WP-07 Supplemental initial proposal the Recommendations as intended by the parties. *Id*.

1.5.2 Post-WP-07 Supplemental ROD Settlement Efforts

Following the publication of the WP-07 Supplemental ROD in 2008, BPA and principals from various IOU and COU groups continued to explore the possibility of settlement. Evaluation Study, REP-12-FS-BPA-01, section 4.1. Settlement discussions continued through the fall and winter of 2008 and moved into 2009. *Id*. While these discussions were ongoing, as noted above, petitions challenging BPA's implementation of the REP were filed with the Ninth Circuit. *Id*. The first challenge was to BPA's Lookback decisions in the WP-07 Supplemental proceeding. *Assoc. of Pub. Agency Customers v. Bonneville Power Admin*., Nos. 08-74725 *et al*. (*APAC*). The second challenge was to the 2008 Residential Purchase and Sale Agreements offered to BPA's utility customers participating in the REP. *Idaho Pub. Utilities Comm'n v. Bonneville Power Admin*., Nos. 08-74927 *et al*. (*IPUC*). As the briefing in these cases moved forward, BPA and representatives for the COUs and IOUs met to discuss the possibility of involving a mediator in the REP settlement discussions. In November 2009, the parties tentatively agreed to engage a mediator following the completion of the briefing in *APAC* and *IPUC*. Evaluation Study, REP-12-FS-BPA-01, section 4.1. Mediation sessions were scheduled to begin in mid-April 2010 and continue until late May 2010. *Id*.

1.5.3 The 2010 REP Litigation Mediation and the 2010 Agreement in Principle

Mediation on the REP litigation commenced on April 15, 2010, in Portland, Oregon. *Id*. Leading the mediation sessions was former Federal District Court Judge Layn Phillips, a nationally renowned mediator. Assisting Judge Phillips was Bernard Schneider. *Id*. The parties also provided the mediator with a technical panel made up of three experts on the operation and implementation of the REP and BPA ratemaking. Because many of the issues in the mediation would affect the prospective implementation of the REP, the litigants invited regional parties not directly involved in the litigation to participate in the mediation. *Id*. In total, more than 50 litigants and other parties participated in the mediation. *Id*. The mediation was scheduled to end in May, but discussions between the parties and the mediator continued through the end of June 2010. *Id*. Although by the conclusion of these sessions the litigants and parties had not achieved a global settlement, significant progress had been made toward reaching a compromise on all existing claims and the future implementation of the REP. Principals for most of the litigants agreed to continue to work toward a settlement. *Id*.

In early September 2010, with assistance from the mediator, representatives for a substantial majority of the litigants and other regional parties agreed to a non-binding Agreement in Principle (AIP). *Id*. The AIP committed the negotiating parties to work in good faith on a final settlement of the REP that adhered to the terms and conditions outlined in the AIP. *Id*.; *see also* AIP, 2012 REP Settlement Evaluation and Analysis Study Documentation (Evaluation Study Documentation), REP-12-E-BPA-01B, at 2-11.

1.5.4 Drafting and Offering of the March 3, 2011, Version of the 2012 REP Settlement

Drafting of the 2012 REP Settlement ensued, with agreement over the key elements reached in December 2010.[4] Thereafter, the negotiating parties continued to negotiate other terms of the Settlement, such as dispute resolution, potential legislative language, and other provisions. Murphy and Kallstrom, REP-12-E-JP02-02, at 24. These discussions concluded in March 2011, and a final Settlement was submitted to regional parties for signature on or about March 3, 2011. *See* Settlement, REP-12-E-BPA-11.

In order for the Settlement to become effective, the March 3, 2011, version of the Settlement contained a condition precedent that required the following parties (excluding BPA) to sign by April 15, 2011:

> (a) COUs, having in the aggregate, Transition High Water Marks (as defined in the TRM) equal to or greater than 91 percent of the total Transition High Water Marks of all COUs, have signed and delivered to BPA this Settlement Agreement, (b) the Public Power Council and Northwest Requirements Utilities have signed and delivered to BPA this Settlement Agreement, (c) Pacific Northwest Generating Cooperative has signed and delivered to BPA this Settlement Agreement, and (d) each entity of the IOU Group has signed and delivered to BPA this Settlement Agreement ….

Settlement, § 1.2.2(i), REP-12-E-BPA-11. If the requisite number of parties and entities did not sign by the April 15, 2011 deadline, the Settlement would become "void *ab initio*." *Id*. § 1.2.2.

[4] BPA's legal and ratemaking staffs participated in the negotiations of the Settlement with representatives of the IOUs and COUs until the commencement of the REP-12 proceeding with the publication of a Federal Register notice on December 16, 2010. Thereafter, BPA continued to participate in the negotiations, but only during publicly noticed meetings. *See, e.g.*, ROD section 1.6.4.

By the close of business on April 15, 2011, the IOUs, public utility commissions for three states, Citizens' Utility Board of Oregon, and the COU representative groups of Public Power Council, Northwest Requirements Utilities, and Pacific Northwest Generating Cooperative had signed the Settlement, thereby satisfying the conditions set forth in § 1.2.2(b), (c), and (d). However, the condition in part (a) that required COUs accounting for 91 percent of the Transition Period High Water Marks (THWM) of all COUs to sign the Settlement had not been met. Instead, COUs representing 81.5 percent of the THWM (roughly 83 percent of the COU customers) signed the Settlement. *See* Forman and Bliven, REP-12-E-BPA-27, at 2.

1.5.5 <u>Drafting and Offering the April 22, 2011, Version of the 2012 REP Settlement</u>

Even though the 91 percent threshold amount of COU THWM load had not been achieved, the negotiating IOU and COU parties—along with state utility commissions from Oregon, Idaho, and Washington, and CUB—were highly encouraged by the overwhelming level of support shown for the Settlement. Together, the group of BPA customers that had signed the Settlement accounted for more than *90 percent* of the electric load in the Pacific Northwest. *See* Carrasco *et al.*, REP-12-E-JP05-02, at 4. Describing this level of support for the Settlement as "remarkable," representatives from both IOUs and COUs stated publicly that "we cannot recall any other circumstance in which the public and private utilities serving more than 90% of the regional load have come together in a common cause." *Id*. at 4. Calling this "opportunity for regional peace … too important to let … slip away," representatives from the IOU and COU groups quickly re-engaged in around-the-clock negotiations in an attempt to revise the condition precedent in the Settlement. *Id*. at 5. On April 22, 2011, exactly one week after the original deadline had passed, a coalition of IOU and COU parties representing 90 percent of regional load filed a revised 2012 REP Settlement in the REP-12 proceeding. *See* Notice of Proposed Form of Revised REP Settlement Agreement, REP-12-M-SE-08. The revised Settlement was identical to the previous settlement in all respects except that the percentage of COU THWM load needed to meet the condition precedent was changed to 75 percent and the deadline for signing the revised Settlement was set for June 3, 2011. *Id*.; *see also* Forman and Bliven, REP-12-E-BPA-27, at 3, and Attachment A, at A-3.

By June 6, 2011, BPA notified parties that the conditions precedent in the Settlement had been met. In total, in addition to the same IOUs, state public utility commissions, and COU and IOU interest groups that had signed the earlier version of the Settlement, *88.1 percent* of the COU THWM load had also executed the Settlement, *6.6 percent more THWM than originally signed on April 15*. For the first time in the 30-year history of the REP, a *joint* Settlement of the REP involving virtually all of BPA's customers had been achieved, conditioned upon the Administrator's decision in this proceeding.

1.5.6 <u>Significance of Achieving a Broad REP Settlement</u>

The historical significance of achieving a settlement of the REP that is supported by a large segment of BPA's customers is not lost on BPA. A broadly supported settlement of the REP has been a long-hoped-for but elusive goal. The complexity of settling the REP has been compounded because, as aptly noted by counsel for a large coalition of COUs, "the IOUs and

COUs have approached the REP and section 7(b)(2) from dramatically different perspectives since adoption of the Act, and those perspectives are sometimes charged with emotion." Murphy and Kallstrom, REP-12-E-JP02-02, at 18. Nevertheless, despite these fundamental differences, one of the largest coalitions in recent history of COUs, IOUs, and aligned interest groups have put aside their differences and reached a major agreement that settles existing litigation and establishes a stable and predictable implementation of the REP for the next 17 years. These parties collectively represent roughly *93 percent* of the load served in the Pacific Northwest. The enormous amount of effort expended by representatives of the COUs, IOUs, public utility commissions, ratepayer advocacy groups, PPC, NRU, and PNGC, who spent hundreds of hours in intense negotiations to achieve this settlement, must be commended.

The fruit of those efforts, the 2012 REP Settlement, is now before BPA. The question to be considered in this proceeding is whether BPA may, consistent with the Northwest Power Act, join these parties in ending the current disputes and avoid perpetuating the cycle of litigation over the REP for a period of 17 years. It is to that question that BPA now turns.

1.6 The Residential Exchange Program Settlement Agreement Proceeding (REP-12)

1.6.1 Overview of the REP-12 Proceeding

Although, as the Administrator stated in the WP-07 Supplemental ROD, WP-07-A-05, at xx-xxi, BPA firmly believes that settlement of the existing REP litigation is in the interest of all BPA ratepayers, nevertheless, BPA must ensure that the terms and conditions in the 2012 REP Settlement are reasonable and comply with all relevant statutory provisions before executing the Settlement. *See Proposed Residential Exchange Program Settlement Agreement Proceeding (REP-12); Public Hearing and Opportunities for Public Review and Comment*, 75 Fed. Reg. 78694, at 78702 (2010).

The negotiating parties presented BPA with the essential components of the Settlement in mid-December 2010. BPA reviewed the draft Settlement and determined that it had sufficient detail for BPA to evaluate whether the Settlement complies with BPA's statutes and is otherwise reasonable. Consequently, on December 16, 2010, BPA commenced the Residential Exchange Program Settlement Agreement Proceeding (REP-12), pursuant to the procedural rules of section 7(i) of the Northwest Power Act, 16 U.S.C. § 839e(i), to provide a forum in which BPA and other interested parties could evaluate the reasonableness and legal sufficiency of the proposed Settlement in order to determine whether the Administrator should sign the Settlement. 75 Fed. Reg. 78694, at 78702 (2010).

To test the reasonableness of the Settlement and to determine whether it comports with BPA's statutory requirements, BPA proposed to perform an analysis that developed a range of projected rate protection for BPA's preference customers (and concomitant REP benefits the IOUs would receive) under the section 7(b)(2) rate test in the absence of the Settlement. *Id*. The range of rate protection and REP benefits would be developed by quantifying the major issues being litigated by BPA, the IOUs, the COUs, CUB, and state utility commissions from Oregon, Idaho, and Washington in the current and pending litigation. *Id*. For each of these main issues, most of which involved the section 7(b)(2) rate test, BPA would develop a 17-year projection of rate protection and REP benefits that was based on the parties' respective legal positions. *Id*. The amounts of rate protection and REP benefits allowed under these various assumptions would then be compared to the rate protection and REP benefits afforded to the IOUs under the Settlement to test whether the terms of the Settlement were reasonable and consistent with the protections provided by law. *Id*. BPA also tested whether the benefits provided under the Settlement would be distributed to the IOUs in a manner consistent with section 5(c) of the Northwest Power Act. *Id*. In addition to the analysis of the litigation positions, BPA analyzed the effects of other factors that could affect future ASCs and PF rates, including changes in costs, loads, and other revenues. Evaluation Study, REP-12-FS-BPA-01, section 6.4.

In the Federal Register notice, BPA explained that at the conclusion of the REP-12 proceeding the Administrator would determine, after reviewing all evidence and arguments contained in the record, whether the terms of the Settlement comport with BPA's statutory requirements. 75 Fed. Reg. 78694, at 78702 (2010). If the Administrator determines that the settlement is consistent with applicable law, including the section 7(b)(2) rate test and section 5(c), and is broadly supported by BPA's customers and other interested parties, he will sign the Settlement and set BPA's FY 2012–2013 rates in accordance with the terms of the Settlement. *Id*. In such case, the Settlement will replace BPA's current construct of withholding REP benefits due the IOUs for their residential and small farm consumers and paying Lookback refund credits to eligible COUs as described in the WP-07 Supplemental ROD, the 2008 RPSA ROD, and the WP-10 ROD. *Id*. Instead, the Settlement will delineate the amount of rate protection afforded to COUs for the term of the agreement and resolve the issues relating to BPA's calculation and collection of the Lookback Amounts. Together, these features of the Settlement will act as a complete replacement for the decisions BPA reached in the WP-07 Supplemental ROD, the 2008 RPSA ROD, and the WP-10 ROD regarding the interpretation and implementation of sections 7(b)(2) and 7(b)(3) and the calculation, formulation, and collection of the Lookback Amounts. In this way, BPA's adoption of the Settlement will supplant the agency's previous response to the Court's decisions in *PGE* and *Golden NW*, thereby obviating the need to continue the REP-related litigation over BPA's prior decisions in the WP-07 Supplemental ROD, the 2008 RPSA ROD, and the WP-10 ROD.

To address the possibility that the Administrator would determine that the Settlement was not consistent with BPA's statutory duties or was otherwise unlawful, and also to address the possibility that the Settlement's conditions precedent were not met, BPA also proposed, as part of the REP-12 proceeding, an implementation of the REP for the FY 2012–2013 rates in the event the Settlement was not adopted. *Id*. at 78695. This alternative to the Settlement included a proposed implementation of the section 7(b)(2) rate test and a determination of the amount of Lookback refunds to collect from IOUs for the FY 2012–2013 rate period. *Id*. at 78702.

1.6.2 Procedural History of the REP-12 Proceeding

The Federal Register notice announcing the commencement of the REP-12 proceeding was issued on December 16, 2010. 75 Fed. Reg. 78694 (2010). The REP-12 proceeding was conducted with the full procedural rights afforded by section 7(i) of the Northwest Power Act, including a hearing with cross-examination, public opportunities to provide both oral and written views related to BPA's proposal, opportunities to offer refutation or rebuttal material, and this ROD. *Id*. at 78695.

BPA's Initial Proposal was filed on December 17, 2010. *Id*. at 78696. Subsequently, parties filed updated drafts of the Settlement reflecting additional edits by the negotiators. On February 25, 2011, BPA filed supplemental direct testimony responding to the new additions. Parties' direct cases, including responses to BPA's Initial Proposal, were filed on February 15, 2011. *See* Forman *et al*., REP-12-E-BPA-10, at 1-2. Rebuttal testimony in response to parties' direct testimonies was filed on March 15, 2011. *See* Order, REP-12-HOO-01. Rebuttal on BPA's supplemental direct testimony was filed by March 28, 2011. *See* Order, REP-12-HOO-13, at 1-2. Cross-examination occurred on April 4-5, 2011. BPA received final revisions to the Settlement on April 22, 2011. *See* Notice of Proposed Form of Revised REP Settlement Agreement, REP-12-M-SE-08. BPA subsequently moved to reopen the record and permit the filing of direct and rebuttal testimony on the final edits. *See* BPA Motion, REP-12-M-BPA-09. The Hearing Officer granted BPA's motion, and direct testimony and rebuttal testimony deadlines were established. *See* Order, REP-12-HOO-19. BPA and a joint group of IOUs and COUs filed direct testimony responding to the final revisions to the Settlement. No rebuttal testimony was filed.

1.6.3 Standstill Agreement and Incorporation of the Records from the WP-07 Supplemental Rate Proceeding, the 2008 RPSA Proceeding, and the WP-10 Wholesale Power Rate Proceeding

Because it was unknown whether the Administrator would adopt the Settlement, the scope of the REP-12 proceeding permitted the inclusion of material related both to the proposed Settlement and to BPA's traditional implementation of the REP, including BPA's implementation of the section 7(b)(2) rate test and Lookback refund-related decisions. 75 Fed. Reg. 78694, at 78696 (2010). Many of the parties had thoroughly briefed BPA's implementation of the section 7(b)(2) rate test and Lookback-related decisions in the WP-07 Supplemental and WP-10 proceedings. To avoid the administrative burden of repeating all of these arguments in the REP-12 proceeding, BPA and the litigants agreed to a "Standstill Agreement" whereby the parties and BPA would agree to incorporate by reference arguments and evidence presented in these prior two BPA rate proceedings. To effectuate the parties' agreement in the Standstill Agreement, BPA filed a Motion with the Hearing Officer requesting the issuing of an Order that incorporated by reference the prior arguments and evidence of the parties and BPA related to a number of topics. BPA Motion, REP-12-M-BPA-02. The Hearing Officer granted BPA's Motion. Order, REP-12-HOO-11. The Order provides as follows:

> Many of the issues that would likely be litigated in the REP-12 Settlement Proceeding have already been fully briefed by the parties and responded to in BPA's 2007 Supplemental Wholesale Power Rate Case Administrator's Final Record of Decision, BPA Document No. WP-07-A-05, ("WP-07 [Supplemental] ROD"), BPA's 2010 Wholesale Power Rate Case Administrator's Final Record of Decision, BPA Document No. WP-10-A-05 ("WP-10 ROD"), and BPA's Final Record of Decision regarding the 2008 RPSAs ("2008 RPSA ROD"). Because

(b) Lookback Recovery and Return (*e.g.*, Chapter 15.0);

(c) Allocation of 7(b)(3) Trigger (*e.g.*, Chapter 8).

(7) The arguments submitted by parties and BPA regarding the decisions made in the following sections of the 2008 RPSA ROD are hereby deemed to have been made in the REP-12 Settlement Proceeding, except to the extent a party or BPA expressly modifies such arguments in this proceeding.

(a) Termination and Reentry Issues (*e.g.*, Section III.A);

(b) Balancing Account Issues (*e.g.*, Section III.B);

(c) *In lieu* Issues (*e.g.*, Section III.C);

(d) Other Issues (*e.g.*, Section III.D).

(8) Nothing in this Order shall be construed as limiting or otherwise restricting the authority of the BPA Administrator to make final decisions in this proceeding.

Id. at 1-4.

1.6.4 <u>Workshops and Publicly Noticed Meetings</u>

As noted above, while the essential components of the Settlement had been drafted by December 2010, a number of tertiary provisions of the Settlement had not been completed by the commencement of the REP-12 proceeding. Consequently, throughout the REP-12 proceeding, the negotiating parties provided regular updates to various provisions of the proposed Settlement. Because of *ex parte* restrictions, these updates were provided by the representatives of the COUs and IOUs through filed submissions to BPA's secure rate case Web site and were automatically served on all parties to the proceeding. In the event Staff had questions or concerns with the proposed revisions, BPA held a publicly noticed workshop at which BPA and any party could provide comments on the proposed revisions to the REP Settlement. Several of these public workshops were held throughout the REP-12 proceeding. A list of these publicly noticed meetings is provided below.

Notice emailed January 7, 2011. Meeting held on January 12, 2011, at BPA Headquarters. Subject: Discussion of Residential Exchange Program Settlement, among other topics.

Notices emailed January 19 and 26, 2011. Meeting held on January 27, 2011, at BPA Headquarters. Subject: Discussion of dispute resolution provision proposed to be included in the 2012 Residential Exchange Settlement Agreement by the IOU and certain COU parties.

Notices emailed February 3, 8, and 10, 2011. Meeting held on February 11, 2011, at BPA Headquarters. Subject: Discussion of February 1, 2011 redlined version of the 2012 Residential Exchange Program Settlement Agreement.

Notice emailed February 11, 2011. Meeting held on February 17, 2011, at Idaho Consumer-Owned Utilities. Subject: BPA presentation regarding the Residential Exchange Program settlement.

Notices emailed February 16 and 25, 2011. Meeting held on February 28, 2011, at BPA Headquarters. Subject: Discussion of redlined version of the 2012 Residential Exchange Program Settlement Agreement.

Notice emailed March 4, 2011. Meeting held on March 7, 2011, at Clallam County PUD. Subject: BPA staff presentation regarding Residential Exchange Program settlement.

Notice emailed March 4, 2011. Meeting held on March 8, 2011, at Parkland Light and Water Company. Subject: BPA staff presentation regarding Residential Exchange Program settlement.

Notice emailed March 4, 2011. Meeting held on March 29, 2011, at Oregon Trail Electric Cooperative. Subject: BPA Administrator's presentation regarding Residential Exchange Program settlement.

Notice emailed March 7, 2011. Meeting held on March 9, 2011, at Hampton Inn, Boise, ID. Subject: Presentation regarding Residential Exchange Program settlement.

Notice emailed March 14, 2011. Meeting held on March 16, 2011, at Shilo Inn & Suites, Portland, OR. Subject: Presentation regarding participation in the Residential Exchange Program settlement.

Notices emailed March 11, 16, and 18, 2011. Meeting held on March 18, 2011, at BPA Headquarters. Subject: Discussion of proposals pertaining to settlement of consumer-owned utilities' participation in the Residential Exchange Program.

Notices emailed March 22 and 24, 2011. Meeting held on March 25, 2011, at BPA Headquarters. Subject: Discussion of proposal to settle consumer-owned utilities' participation in the Residential Exchange Program.

Notice emailed March 25, 2011. Meeting held on March 28, 2011, at Lewis County PUD. Subject: BPA staff presentation regarding the REP Settlement.

Notice emailed March 30, 2011. Meeting held on April 4, 2011, at Grays Harbor PUD. Subject: BPA staff presentation regarding the REP Settlement.

1.7 Concurrent Proceedings

1.7.1 BP-12 Rate Proceeding

Concurrent with the REP-12 section 7(i) proceeding, BPA is holding a consolidated rate proceeding, Docket No. BP-12, that establishes power and transmission rates for FY 2012–2013. The Federal Register notice for the BP-12 rate proceeding identified the issues within the scope of the case and those excluded from review.

In the BP-12 rate proceeding, Power Services is implementing the Tiered Rate Methodology for the first time to coincide with the commencement of power deliveries under new Regional Dialogue power sales contracts beginning in FY 2012. The TRM provides for a two-tiered