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

2007 Supplemental Wholesale Power Rate Case
Final Proposal

FY 2009 WHOLESALE POWER RATE DEVELOPMENT STUDY DOCUMENTATION

Volume 2

September 2008

WP-07-FS-BPA-13B

BONNEVILLE POWER ADMINISTRATION

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Average System Cost $/MWh **Table 1**

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Avista	50.28	48.42	48.69	48.47	48.41
Centralia	35.56	36.71	36.68	38.27	38.26
Franklin	45.74	47.59	47.24	50.01	49.62
Idaho	33.86	33.96	34.34	34.60	34.99
NorthWestern	54.84	55.36	56.06	56.85	57.72
PacifiCorp	51.82	49.68	49.47	48.95	48.56
PGE	57.53	56.01	56.43	56.43	56.59
PSE	59.71	59.72	60.36	60.92	61.56
Snohomish	38.08	39.63	39.81	41.76	41.97

Total Contract System Cost ($ in millions) **Table 2**

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Avista	481.8	473.5	484.2	492.3	500.9
Centralia	10.3	10.9	11.2	12.0	12.3
Franklin	46.8	49.8	50.3	54.1	54.6
Idaho	534.0	545.3	559.8	568.1	580.7
NorthWestern	375.4	391.4	409.3	428.7	449.5
PacifiCorp	1,153.7	1,115.8	1,122.3	1,121.8	1,124.3
PGE	1,079.8	1,074.7	1,107.1	1,131.8	1,160.3
PSE	1,374.7	1,386.8	1,411.8	1,434.3	1,458.1
Snohomish	277.4	292.7	296.5	313.5	317.4

Total Contract System Load (GWh) **Table 3**

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Avista	9,582	9,778	9,946	10,157	10,348
Centralia	291	298	305	313	321
Franklin	1,023	1,047	1,065	1,082	1,101
Idaho	15,772	16,059	16,300	16,422	16,596
NorthWestern	6,845	7,070	7,301	7,541	7,788
PacifiCorp	22,264	22,461	22,686	22,919	23,151
PGE	18,769	19,189	19,618	20,057	20,505
PSE	23,022	23,222	23,391	23,545	23,687
Snohomish	7,284	7,386	7,447	7,508	7,562

New Large Single Loads (MWh) **Table 4**

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Avista	61,449	61,449	61,449	61,449	61,449
Centralia	-	-	-	-	-
Franklin	-	-	-	-	-
Idaho	385,440	385,440	385,440	385,440	385,440
NorthWestern	-	-	-	-	-
PacifiCorp	342,068	342,068	342,068	342,068	342,068
PGE	328,992	328,992	328,992	328,992	328,992
PSE	-	-	-	-	-
Snohomish	-	-	-	-	-

New Large Single Load Costs ($) **Table 4A**

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Avista	4,771,005	4,416,922	4,446,260	4,361,813	4,298,313
Centralia	-	-	-	-	-
Franklin	-	-	-	-	-
Idaho	30,492,835	29,297,863	29,244,354	29,086,338	28,938,635
NorthWestern	-	-	-	-	-
PacifiCorp	19,865,032	19,078,938	19,052,436	18,876,147	18,726,097
PGE	24,127,751	22,847,185	22,864,160	22,628,883	22,365,495
PSE	-	-	-	-	-
Snohomish	-	-	-	-	-

Avista

Contract System Costs and ASC w/ New Resource Additions

Table 5

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Contract System Cost ($)					
Production	426,553,083	418,576,017	429,968,037	438,593,985	447,787,283
Transmission	60,000,388	59,329,051	58,710,865	58,065,786	57,450,436
NLSL Fully Allocated Cost ($/MWh)	77.64	71.88	72.36	70.98	69.95
(Less) New Large Single Load Costs (d)	4,771,005	4,416,922	4,446,260	4,361,813	4,298,313
Total Contract System Cost	481,782,465	473,488,147	484,232,641	492,297,957	500,939,406
Contract System Load (MWh)					
Total Retail Load @ Meter	9,163,546	9,349,910	9,508,840	9,709,299	9,890,789
(Less) New Large Single Load	61,449	61,449	61,449	61,449	61,449
Total Retail Load (Net of NLSL) (d)	9,102,097	9,288,461	9,447,391	9,647,850	9,829,340
Distribution Loss (f)	480,170	489,935	498,263	508,767	518,277
Total Contract System Load	9,582,267	9,778,396	9,945,654	10,156,617	10,347,617
Average System Cost $/MWh	50.28	48.42	48.69	48.47	48.41

Centralia

Contract System Costs and ASC w/ New Resource Additions

Table 6

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Contract System Cost ($)					
Production	8,931,977	9,508,022	9,740,887	10,495,488	10,753,858
Transmission	1,410,451	1,434,131	1,461,501	1,489,785	1,519,456
NLSL Fully Allocated Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00
(Less) New Large Single Load Costs (d)	0	0	0	0	0
Total Contract System Cost	10,342,428	10,942,154	11,202,389	11,985,273	12,273,314
Contract System Load (MWh)					
Total Retail Load @ Meter	276,991	283,912	290,833	298,227	305,531
(Less) New Large Single Load	0	0	0	0	0
Total Retail Load (Net of NLSL) (d)	276,991	283,912	290,833	298,227	305,531
Distribution Loss (f)	13,850	14,196	14,542	14,911	15,277
Total Contract System Load	290,840	298,108	305,375	313,138	320,808
Average System Cost $/MWh	35.56	36.71	36.68	38.27	38.26

Franklin | **Contract System Costs and ASC w/ New Resource Additions** | **Table 7**

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Contract System Cost ($)					
Production	46,464,644	49,467,433	49,965,516	53,756,643	54,298,688
Transmission	339,921	334,953	330,161	325,252	320,254
NLSL Fully Allocated Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00
(Less) New Large Single Load Costs (d)	0	0	0	0	0
Total Contract System Cost	46,804,565	49,802,386	50,295,677	54,081,895	54,618,941
Contract System Load (MWh)					
Total Retail Load @ Meter	974,500	996,750	1,014,000	1,030,000	1,048,250
(Less) New Large Single Load	0	0	0	0	0
Total Retail Load (Net of NLSL) (d)	974,500	996,750	1,014,000	1,030,000	1,048,250
Distribution Loss (f)	48,725	49,838	50,700	51,500	52,413
Total Contract System Load	1,023,225	1,046,588	1,064,700	1,081,500	1,100,663
Average System Cost $/MWh	45.74	47.59	47.24	50.01	49.62

Idaho

Contract System Costs and ASC
w/ New Resource Additions

Table 8

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Contract System Cost ($)					
Production	470,949,913	481,694,355	496,739,225	505,581,825	518,655,158
Transmission	93,579,418	92,933,257	92,316,991	91,643,186	91,009,961
NLSL Fully Allocated Cost ($/MWh)	79.11	76.01	75.87	75.46	75.08
(Less) New Large Single Load Costs (d)	30,492,835	29,297,863	29,244,354	29,086,338	28,938,635
Total Contract System Cost	534,036,495	545,329,749	559,811,862	568,138,673	580,726,484
Contract System Load (MWh)					
Total Retail Load @ Meter	14,990,809	15,256,830	15,481,163	15,593,539	15,755,103
(Less) New Large Single Load	385,440	385,440	385,440	385,440	385,440
Total Retail Load (Net of NLSL) (d)	14,605,369	14,871,390	15,095,723	15,208,099	15,369,663
Distribution Loss (f)	1,166,538	1,187,238	1,204,695	1,213,440	1,226,012
Total Contract System Load	15,771,907	16,058,628	16,300,418	16,421,539	16,595,675
Average System Cost $/MWh	33.86	33.96	34.34	34.60	34.99

NW

Contract System Costs and ASC w/ New Resource Additions

Table 9

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Contract System Cost ($)					
Production	325,602,601	343,066,995	362,474,784	383,344,870	405,615,201
Transmission	49,773,010	48,305,130	46,859,814	45,371,968	43,907,962
NLSL Fully Allocated Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00
(Less) New Large Single Load Costs (d)	0	0	0	0	0
Total Contract System Cost	375,375,611	391,372,125	409,334,598	428,716,838	449,523,163
Contract System Load (MWh)					
Total Retail Load @ Meter	6,334,276	6,542,040	6,756,619	6,978,236	7,207,122
(Less) New Large Single Load	0	0	0	0	0
Total Retail Load (Net of NLSL) (d)	6,334,276	6,542,040	6,756,619	6,978,236	7,207,122
Distribution Loss (f)	510,787	527,540	544,844	562,715	581,172
Total Contract System Load	6,845,062	7,069,580	7,301,463	7,540,951	7,788,294
Average System Cost $/MWh	54.84	55.36	56.06	56.85	57.72

PAC

Contract System Costs and ASC w/ New Resource Additions

Table 10

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Contract System Cost ($)					
Production	1,001,429,090	964,635,860	972,845,032	973,829,991	977,745,929
Transmission	172,107,523	170,231,271	168,517,142	166,841,503	165,247,996
NLSL Fully Allocated Cost ($/MWh)	58.07	55.78	55.70	55.18	54.74
(Less) New Large Single Load Costs (d)	19,865,032	19,078,938	19,052,436	18,876,147	18,726,097
Total Contract System Cost	1,153,671,581	1,115,788,194	1,122,309,738	1,121,795,347	1,124,267,828
Contract System Load (MWh)					
Total Retail Load @ Meter	22,016,008	22,207,898	22,427,330	22,654,332	22,880,278
(Less) New Large Single Load	342,068	342,068	342,068	342,068	342,068
Total Retail Load (Net of NLSL) (d)	21,673,940	21,865,830	22,085,262	22,312,264	22,538,210
Distribution Loss (f)	590,029	595,172	601,052	607,136	613,191
Total Contract System Load	22,263,969	22,461,002	22,686,314	22,919,400	23,151,401
Average System Cost $/MWh	51.82	49.68	49.47	48.95	48.56

PGE

Contract System Costs and ASC w/ New Resource Additions

Table 11

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Contract System Cost ($)					
Production	989,569,836	982,643,846	1,014,355,729	1,037,931,055	1,065,378,501
Transmission	114,363,956	114,881,485	115,645,517	116,453,938	117,336,870
NLSL Fully Allocated Cost ($/MWh)	73.34	69.45	69.50	68.78	67.98
(Less) New Large Single Load Costs (d)	24,127,751	22,847,185	22,864,160	22,628,883	22,365,495
Total Contract System Cost	1,079,806,041	1,074,678,147	1,107,137,086	1,131,756,110	1,160,349,876
Contract System Load (MWh)					
Total Retail Load @ Meter	18,238,510	18,639,757	19,049,832	19,468,928	19,897,245
(Less) New Large Single Load	328,992	328,992	328,992	328,992	328,992
Total Retail Load (Net of NLSL) (d)	17,909,518	18,310,765	18,720,840	19,139,936	19,568,253
Distribution Loss (f)	859,034	877,933	897,247	916,987	937,160
Total Contract System Load	18,768,552	19,188,698	19,618,087	20,056,923	20,505,413
Average System Cost $/MWh	57.53	56.01	56.43	56.43	56.59

Puget

Contract System Costs and ASC w/ New Resource Additions

Table 12

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Contract System Cost ($)					
Production	1,287,048,182	1,299,213,211	1,324,035,089	1,346,357,375	1,369,844,418
Transmission	87,615,204	87,580,901	87,751,169	87,991,341	88,294,956
NLSL Fully Allocated Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00
(Less) New Large Single Load Costs (d)	0	0	0	0	0
Total Contract System Cost	1,374,663,386	1,386,794,112	1,411,786,258	1,434,348,715	1,458,139,373
Contract System Load (MWh)					
Total Retail Load @ Meter	21,927,453	22,118,040	22,279,295	22,425,579	22,561,132
(Less) New Large Single Load	0	0	0	0	0
Total Retail Load (Net of NLSL) (d)	21,927,453	22,118,040	22,279,295	22,425,579	22,561,132
Distribution Loss (f)	1,094,180	1,103,690	1,111,737	1,119,036	1,125,800
Total Contract System Load	23,021,633	23,221,730	23,391,032	23,544,615	23,686,933
Average System Cost $/MWh	59.71	59.72	60.36	60.92	61.56

Snohomish

Contract System Costs and ASC w/ New Resource Additions

Table 13

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Contract System Cost ($)					
Production	239,609,815	254,546,263	257,833,058	274,327,600	277,644,989
Transmission	37,780,520	38,148,568	38,641,922	39,188,191	39,772,181
NLSL Fully Allocated Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00
(Less) New Large Single Load Costs (d)	0	0	0	0	0
Total Contract System Cost	277,390,335	292,694,831	296,474,980	313,515,790	317,417,170
Contract System Load (MWh)					
Total Retail Load @ Meter	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
(Less) New Large Single Load	0	0	0	0	0
Total Retail Load (Net of NLSL) (d)	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
Distribution Loss (f)	346,873	351,704	354,636	357,506	360,114
Total Contract System Load	7,284,334	7,385,777	7,447,346	7,507,618	7,562,386
Average System Cost $/MWh	38.08	39.63	39.81	41.76	41.97

2008 Base ASCs with Incremental ASC Deltas from New Resoure Additions ($/MWh) Table 14

Avista	Base 2009	$	50.28	No Resourse Additions									
Centralia	Base 2009	$	35.56	No Resourse Additions									
Franklin	Base 2009	$	45.74	No Resourse Additions									
Idaho	Base 2009	$	33.86	No Resourse Additions									
NorthWestern	Base 2009	$	54.84	No Resourse Additions									
				Lake Side Capital Building		Group 1		CCCT Plant West		Group 3		Group 4	
PacifiCorp	Base 2009	$	47.98	$	0.83	$	1.26	$	0.33	$	0.93	$	0.48
				Port Westward		Biglow Canyon		Selective Water Withdrawal		Biglow Canyon 2			
PGE	Base 2009	$	50.49	$	3.13	$	1.37	$	0.60	$	1.94		
PSE	Base 2009	$	59.71	No Resourse Additions									
Snohomish	Base 2009	$	38.08	No Resourse Additions									

Tables for:

Avista

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME: **Avista Utilities**
End of Year Report Period: **2006**
ASC Filing Date: **5/7/2008** Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST			-	-	-
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD	15,259,132	14,889,662	369,470	-
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST	4,420,269	-	1,517,348	2,902,921
Total Intangible Plant					**$ 19,679,401**	**$ 14,889,662**	**$ 1,886,818**	**$ 2,902,921**
Production Plant:								
Steam Production	204-207	310-317	PROD		378,625,101	378,625,101	-	-
Nuclear Production	204-207	320-326	PROD		0	-	-	-
Hydraulic Production	204-207	330-337	PROD		340,480,980	340,480,980	-	-
Other Production	204-207	340-347	PROD		272,688,068	272,688,068	-	-
Total Production Plant					**$ 991,794,149**	**$ 991,794,149**	**$ -**	**$ -**
Transmission Plant: (i)								
Transmission Plant	204-207	350-359.1	TRANS		383,823,745	-	383,823,745	-
Total Transmission Plant					**$ 383,823,745**	**$ -**	**$ 383,823,745**	**$ -**
Distribution Plant:								
Distribution Plant	204-207	360-374	DIST		832,094,240	-	-	832,094,240
Total Distribution Plant					**$ 832,094,240**	**$ -**	**$ -**	**$ 832,094,240**
General Plant:								
Land and Land Rights	204-207	389	PTD		124,681	56,012	21,677	46,993
Structures and Improvements	204-207	390	PTD		2,042,518	917,582	355,104	769,832
Furniture and Equipment	204-207	391	LABOR		136,601	53,636	15,663	67,302
Transportation Equipment	204-207	392	TD		8,275,752	-	2,612,372	5,663,380
Stores Equipment	204-207	393	PTD		120,561	54,161	20,960	45,440
Tools and Garage Equipment	204-207	394	PTD		2,988,365	1,342,495	519,545	1,126,325
Laboratory Equipment	204-207	395	PTD		3,039,673	1,365,545	528,465	1,145,663
Power Operated Equipment	204-207	396	TD		19,674,347	-	6,210,519	13,463,828
Communication Equipment	204-207	397	PTD		28,330,864	12,727,377	4,925,487	10,677,999
Miscellaneous Equipment	204-207	398	PTD		3,973	1,785	691	1,497
Other Tangible Property	204-207	399	DIRECT	PTD	0	-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD		0	-	-	-
Total General Plant					**$ 64,737,335**	**$ 16,518,593**	**$ 15,210,483**	**$ 33,008,260**
Total Electric Plant In-Service					**$ 2,292,128,870**	**$ 1,023,202,404**	**$ 400,921,046**	**$ 868,005,421**

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Avista Utilities
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008

Revised Amended BPA: 8-4-2008

TABLE 15A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
LESS:						6,393,551		
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD		223,287,652	223,287,652	-	-
Nuclear Production Plant	219	108	PROD		0	-	-	-
Hydraulic Production Plant	219	108	PROD		79,097,867	79,097,867	-	-
Other Production Plant	219	108	PROD		36,139,145	36,139,145	-	-
Transmission Plant (i)	219	108	TRANS		136,875,953	-	136,875,953	-
Distribution Plant	219	108	DIST		256,150,345	-	-	256,150,345
General Plant	219	108	GP		39,680,634	10,125,042	9,323,238	20,232,354
Amortization of Intangible Plant - Account 301	219	111	DIST		0	-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD	2,397,915	2,360,968	36,947	-
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST	4,589,483	1,917,082	1,053,532	1,618,869
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	111	DIST			-	-	-
Capital Lease - Common Plant	219	108	DIRECT			-	-	-
Leasehold Improvements	200-201	108	DIRECT	DIST		-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT		18,092,047	8,127,684	3,145,409	6,818,954
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST		-	-	-
Amortization of Acquisition Adjustments	200-201	115	DIRECT			-	-	-
Depreciation and Amortization Reserve (Other)			DIRECT					
Total Depreciation and Amortization Reserve					$ 796,311,041	$ 361,055,440	$ 150,435,079	$ 284,820,522
Total Net Plant					$ 1,495,817,829	$ 662,146,964	$ 250,485,967	$ 583,184,899

(Total Electric Plant In-Service) - (Total Depreciation & Amortization)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Avista Utilities
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008

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TABLE 15A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation:				29,680,030	18,455,918	3,121,012	8,103,101
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST		0	-	-	-
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD		0	-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST		76,081,096	-	-	76,081,096
Common Plant	356 & 356.1		DIRECT		69,962,275	31,483,024	11,893,587	26,585,665
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST	0	-	-	-
Total					**$ 146,043,371**	**$ 31,483,024**	**$ 11,893,587**	**$ 102,666,761**
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST	13,903,000	-	-	13,903,000
Other Investment	110-111	124	DIST		31,166,335	-	-	31,166,335
Long-Term Portion of Derivative Assets	110-111	175	DIST		25,574,531	-	-	25,574,531
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST		0	-	-	-
Total					**$ 70,643,866**	**$ -**	**$ -**	**$ 70,643,866**
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD		2,121,931	2,121,931	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD		0	-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD		14,019,070	6,297,937	2,437,298	5,283,835
Merchandise (Major Only)	110-112	155	DIST		0	-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST		0	-	-	-
EPA Allowance Inventory	110-112	158.1	PROD		0	-	-	-
EPA Allowances Withheld	110-112	158.2	PROD		0	-	-	-
Stores Expense Undistributed	110-111	163	PTD		0	-	-	-
Prepayments	110-111	165	PTD		6,467,948	2,905,666	1,124,491	2,437,792
Derivative Instrument Assets	110-111	175	DIST		36,402,843	-	-	36,402,843
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST		25,574,531	-	-	25,574,531
Derivative Instrument Assets - Hedges	110-111	176	DIST		0	-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST		0	-	-	-
Total					**$ 33,437,261**	**$ 11,325,533**	**$ 3,561,789**	**$ 18,549,939**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Avista Utilities
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG		17,931,388	8,004,541	3,136,417	6,790,431
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST	0	-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST	0	-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST	323,816,436	28,097,184	7,749,141	287,970,111
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST		8,645,616	-	-	8,645,616
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST		0	-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST		0	-	-	-
Clearing Accounts	110-111	184	DIST		8,046	-	-	8,046
Temporary Facilities	110-111	185	PTDG		0	-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST	31,297,127	8,686,400	982,008	21,628,718
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT		0			
Research, Development, and Demonstration Expenditures	110-111	188	DIST		0	-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG		28,622,766	12,777,154	5,006,468	10,839,145
Accumulated Deferred Income Taxes	110-111	190	DIST		55,602,315	-	-	55,602,315
Total					**$ 465,923,694**	**$ 57,565,279**	**$ 16,874,034**	**$ 391,484,382**
Total Assets and Other Debits					**$ 745,728,222**	**$ 118,829,754**	**$ 35,450,421**	**$ 591,448,048**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Avista Utilities
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Liabilities and Other Credits (Comparative Balance Sheet)								
Current and Accrued Liabilities								
Derivative Instrument Liabilities	112-113	244	DIST		83,652,834	-	-	83,652,834
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST		10,174,378	-	-	10,174,378
Derivative Instrument Liabilities - Hedges	112-115	245	DIST		5,144,457	-	-	5,144,457
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST		5,144,457	-	-	5,144,457
Total					**$ 73,478,456**	**$ -**	**$ -**	**$ 73,478,456**
Deferred Credits								
Customer Advances for Construction	112-113	252	DIST		1,087,069	-	-	1,087,069
Other Deferred Credits	112-113	253	DIRECT	DIST	36,280,631	9,819,591	2,322,841	24,138,198
Other Regulatory Liabilities	112-113	254	DIST	DIST	18,246,960	-	-	18,246,960
Accumulated Deferred Investment Tax Credits	112-113	255	DIST		472,344	-	-	472,344
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT		0			
Unamortized Gain on Reacquired Debt	112-113	257	PTDG		3,282,969	1,465,512	574,231	1,243,226
Accumulated Deferred Income Taxes-Accel. Abort.	112-113	281	DIST		0	-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST		305,474,214	-	-	305,474,214
Accumulated Deferred Income Taxes-Other	112-113	283	DIST		211,989,043	-	-	211,989,043
Total					**$ 576,833,230**	**$ 11,285,103**	**$ 2,897,072**	**$ 562,651,055**
Total Liabilities and Other Credits					**$ 650,311,686**	**$ 11,285,103**	**$ 2,897,072**	**$ 636,129,511**
Total Rate Base					**$ 1,591,234,365**	**$ 769,691,614**	**$ 283,039,316**	**$ 538,503,436**

Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15B: Schedule 1A: Cash Working Capital (f)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	431,008,791	431,008,791	-	-
Total Transmission O&M (i)	19,547,280	-	19,547,280	-
Total Distribution O&M	22,569,058	-	-	22,569,058
Total Customer & Sales	25,860,122	10,184,229	-	15,675,893
Total Administrative and General O&M	49,517,622	17,516,951	5,420,816	26,579,856
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	311,062,630	311,062,630	-	-
Revised Total O&M Expenses	**$ 237,440,243**	**$ 147,647,341**	**$ 24,968,096**	**$ 64,824,807**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 29,680,030**	**$ 18,455,918**	**$ 3,121,012**	**$ 8,103,101**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008

TABLE 15C: Schedule 2: Capital Structure and Rate of Return (b)

Revised Amended BPA: 8-4-2008

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:	
Multi-Jurisdiction Investor-Owned Utility Return Calculation:	11.173%
Consumer-Owned Utility Return Calculation:	
Rate of Return :	11.173%

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order

Note: Multi-jurisdictional utilities must begin on Page 2
Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**
Debt				
Preferred Equity				
Common Equity				
Weighted Cost of Capital	$ -			

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) 35%

Federal Income Tax Factor

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 1,591,234,365	$ 769,691,614	$ 283,039,316	$ 538,503,436
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008

TABLE 15C: Schedule 2: Capital Structure and Rate of Return (b)

Revised Amended BPA: 8-4-2008

Multi-Jurisdiction Investor-Owned Utility Return Calculation

Step 1:

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 1

	Capitalization Structure		Effective Cost		Jurisdictional	Effective Cost -	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**	**Allocation**	**Weighted**	**State Allocation**
Debt		49.3%	6.49%	3.200%	65.83%	2.11%	32.454%
Preferred Equity		4.7%	6.58%	0.310%		0.20%	3.09%
Common Equity		46.0%	10.20%	4.692%		3.09%	30.28%
Weighted Cost of Capital	$ -	**100.00%**		**8.202%**		5.40%	65.83%

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 2

Component	**Amount**	**Percent**	**Embedded**	**Weighted**			
Debt		55.7%	8.43%	4.692%	34.17%	1.60%	19.016%
Preferred Equity		1.8%	7.35%	0.130%		0.04%	0.60%
Common Equity		42.6%	10.40%	4.430%		1.51%	14.55%
Weighted Cost of Capital	$ -	**100.00%**		**9.252%**		3.16%	34.17%

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 3

Component	**Amount**	**Percent**	**Embedded**	**Weighted**			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Jurisdiction	**Rate Base**	**Weighted cost**	**%**	**Weighted Return**		
	$1,037,425,194	8.20%	5.40%	$88,811,740		5.40%
	538,490,337	9.25%	3.16%	46,099,000		3.16%
Total	**$1,575,915,531**		**8.56%**	**$134,910,740**	**100.00%**	**8.56%**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008

TABLE 15C: Schedule 2: Capital Structure and Rate of Return (b)

Revised Amended BPA: 8-4-2008

Multi-Jurisdiction Investor-Owned Utility Return Calculation *(continued)*

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	**35%**	
Federal Income Tax Factor		**2.612%**
*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*		
Federal Income Tax Adjusted Weighted Cost of Capital		**11.173%**
(Weighted Cost of Capital Plus Federal Income Tax Factor)		

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 1,591,234,365	$ 769,691,614	$ 283,039,316	$ 538,503,436
Federal Income Tax Adjusted Weighted Cost of Capital	11.173%	11.173%	11.173%	11.173%
Federal Income Tax Adjusted Return on Rate Base	**$177,786,149**	**$85,996,451**	**$31,623,544**	**$60,166,154**
*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*				

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008

TABLE 15C: Schedule 2: Capital Structure and Rate of Return (b)

Revised Amended BPA: 8-4-2008

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

Debt Issue	Original Amount	Year Issued	Year Due	Interest Rate	Interest Expense
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	$ -				$ -

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 1,591,234,365	$ 769,691,614	$ 283,039,316	$ 538,503,436
Weighted Cost of Debt				
Return on Rate Base				

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilites
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2007

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD		25,443,765	25,443,765	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD		4,589,062	4,589,062	-	-
Steam Power - Maintenance	320-323	510-515	PROD		8,150,550	8,150,550	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD		0	-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD		0	-	-	-
Nuclear - Maintenance	320-323	528-532	PROD		0	-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD		10,915,413	10,915,413	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD		3,988,076	3,988,076	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD		85,535,646	85,535,646	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD		3,397,473	3,397,473	-	-
Other Power - Maintenance	320-323	551-554.1	PROD		1,033,178	1,033,178	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	326	555	PROD		200,083,219	200,083,219	-	-
System Control and Load Dispatching	320-323	556	PROD		638,755	638,755	-	-
Other Expenses	320-323	557	PROD		87,233,654	87,233,654	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (h)			DIRECT					
Total Production Expense					**$ 431,008,791**	**$ 431,008,791**	**$ -**	**$ -**
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS		11,881,367	-	11,881,367	-
Total Operations less Wheeling	320-323	560-567.1	TRANS		4,915,570	-	4,915,570	-
Total Maintenance	320-323	568-574	TRANS		2,750,343	-	2,750,343	-
Total Transmission Expense					**$ 19,547,280**	**$ -**	**$ 19,547,280**	**$ -**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME: **Avista Utilites**
End of Year Report Period: **12/31/2006**
ASC Filing Date: **5/7/2007** Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008TA

TABLE 15D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Distribution Expense:								
Total Operations	320-323	580-589	DIST		9,942,254	-	-	9,942,254
Total Maintenance	320-323	590-598	DIST		12,626,804	-	-	12,626,804
Total Distribution Expense					$ 22,569,058	$ -	$ -	$ 22,569,058
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST		13,364,554	-	-	13,364,554
Customer Service and Information	320-323	906-907	DIST		0	-	-	-
Customer Assistance Expenses (Major only)	320-323	908	DIRECT		11,397,769	10,184,229		1,213,540
Customer Service and Information	320-323	909-910	DIST		166,937	-	-	166,937
Total Sales Expense	320-323	911-917	DIST		930,862	-	-	930,862
Total Customer and Sales Expenses					$ 25,860,122	$ 10,184,229	$ -	$ 15,675,893
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR		17,412,679	6,836,994	1,996,592	8,579,093
Office Supplies & Expenses	320-323	921	LABOR		4,217,501	1,655,979	483,592	2,077,930
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR		28,056	11,016	3,217	13,823
Outside Services Employed	320-323	923	LABOR		9,988,121	3,921,782	1,145,269	4,921,070
Property Insurance	320-323	924	PTDG		1,191,391	531,835	208,389	451,167
Injuries and Damages	320-323	925	LABOR		3,769,353	1,480,016	432,206	1,857,131
Employee Pensions & Benefits	320-323	926	LABOR		1,106,169	434,331	126,837	545,001
Franchise Requirements	320-323	927	DIST		6,230	-	-	6,230
Regulatory Commission Expenses	320-323	928	DIST		1,887,178	-	-	1,887,178
(Less) Duplicate Charges - Credit	320-323	929	PTDG		0	-	-	-
General Advertising Expenses	320-323	930.1	DIST	DIST	8,678	-	-	8,678
Miscellaneous General Expenses	320-323	930.2	DIST		2,950,213	-	-	2,950,213
Rents	320-323	931	DIST		1,068,064	-	-	1,068,064
Transportation Expenses (Non Major)	320-324	933	DIST		0	-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM		5,940,101	2,667,030	1,031,147	2,241,923
Total Administration and General Expenses					$ 49,517,622	$ 17,516,951	$ 5,420,816	$ 26,579,856

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilites
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2007

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Total Operations and Maintenance					$ 548,502,873	$ 458,709,971	$ 24,968,096	$ 64,824,807
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD	337,773	325,457	12,316	-
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST	1,413,353	614,738	279,502	519,112
Steam Production Plant	336	403	PROD		11,388,514	11,388,514	-	-
Nuclear Production Plant	336	403	PROD		0	-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD		6,208,520	6,208,520	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD		0	-	-	-
Other Production Plant	336	403	PROD		13,075,208	13,075,208	-	-
Transmission Plant (i)	336	403	TRANS		9,049,748	-	9,049,748	-
Distribution Plant	336	403	DIST		17,457,435	-	-	17,457,435
General Plant	336	403	GP		3,166,338	807,933	743,953	1,614,452
Common Plant - Electric	336	403	DIRECT		5,293,863	2,378,219	920,369	1,995,275
Common Plant - Electric	336	404	DIRECT		0			
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT		0			
Amortization of Limited Term Electric Plant	336	404	DIRECT		0			
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIRECT		0			
Total Depreciation and Amortization					$ 67,390,752	$ 34,798,589	$ 11,005,888	$ 21,586,274
Total Operating Expenses					$ 615,893,625	$ 493,508,560	$ 35,973,983	$ 86,411,081
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15E: Schedule 3A Items: Taxes

Account Description	FERC Form 1		Funct. Method	Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers					
FEDERAL							
Income Tax	262	409.1	DIST	47,345,130	-	-	47,345,130
Employment Tax	262	408.1	LABOR	8,193,094	3,216,974	939,446	4,036,674
Other Federal Taxes	262	408.1	DIST		-	-	-
TOTAL FEDERAL				**$ 55,538,224**	**$ 3,216,974**	**$ 939,446**	**$ 51,381,804**
STATE AND OTHER							
Property or In-Lieu (c)	262	408.1	PTDG	21,846,838	9,752,391	3,821,276	8,273,171
Unemployment	262	408.1	LABOR		-	-	-
State Income, B&O, et.	262	409.1	DIST	48,758,103	-	-	48,758,103
Franchise Fees	262	408.1	DIST	4,116,694	-	-	4,116,694
Regulatory Commission	262	408.1	DIST	10,310	-	-	10,310
City/Municipal	262	408.1	DIST	11,907	-	-	11,907
Other	262	408.1	DIST	1,529,969	-	-	1,529,969
TOTAL STATE AND OTHER TAXES				**$ 76,273,821**	**$ 9,752,391**	**$ 3,821,276**	**$ 62,700,154**
TOTAL TAXES				**$ 131,812,045**	**$ 12,969,365**	**$ 4,760,722**	**$ 114,081,958**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15F: Schedule 3B Other Included Items

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD	17,989,452	238,789	-	17,750,663
(Less) Regulatory Debits	114	407.3	DIRECT	DIST	337,368	337,368	-	-
Gain from Disposition of Utility Plant	114	411.6	DIRECT	PROD		-	-	-
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST		-	-	-
Gain from Disposition of Allowances	114	411.8	PROD			-	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD			-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD		-	-	-
Total Other Included Items					**$ 17,652,084**	**$ (98,579)**	**$ -**	**$ 17,750,663**
Sales for Resale:								
Sales for Resale	310	447	PROD		175,594,638	175,594,638	-	-
Total Sales for Resale					**$ 175,594,638**	**$ 175,594,638**	**$ -**	**$ -**
Other Revenues:								
Forfeited Discounts	300	450	DIST		-	-	-	-
Miscellaneous Service Revenues	300	451	DIST		447,333	-	-	447,333
Sales of Water and Water Power	300	453	PROD		230,504	230,504	-	-
Rent from Electric Property	300	454	TD		2,592,254	-	818,286	1,773,968
Interdepartmental Rents	300	455	DIST		-	-	-	-
Other Electric Revenues	300	456	DIRECT	PROD	53,187,494	49,084,005	-	4,103,489
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS		10,539,323	-	10,539,323	-
Total Other Revenues					**$ 66,996,908**	**$ 49,314,509**	**$ 11,357,609**	**$ 6,324,790**
Total Other Included Items					**$ 260,243,630**	**$ 224,810,568**	**$ 11,357,609**	**$ 24,075,453**

(Total Other + Total Sales for Resale + Total Other Revenue)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	**Avista Utilities**
End of Year Report Period:	**12/31/2006**
ASC Filing Date:	**5/7/2008**

Amended BPA: 7-8-2008

Revised Amended BPA: 8-18-2008

TABLE 15G: Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses *(From Schedule 3)*	$ 615,893,625	$ 493,508,560	$ 35,973,983	$ 86,411,081
Federal Income Tax Adjusted Return on Rate Base *(From Schedule 2)*	$ 177,786,149	$ 85,996,451	$ 31,623,544	$ 60,166,154
State and Other Taxes *(From Schedule 3a)*	$ 131,812,045	$ 12,969,365	$ 4,760,722	$ 114,081,958
Total Other Included Items *(From Schedule 3b)*	$ 260,243,630	$ 224,810,568	$ 11,357,609	$ 24,075,453
Total Cost	**$ 665,248,189**	**$ 367,663,808**	**$ 61,000,640**	**$ 236,583,740**

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-18-2008

TABLE 15G: Schedule 4: Average System Cost

Contract System Cost		68.44
Production	$ 367,663,808	
Transmission	$ 61,000,640	
(Less) New Large Single Load Costs (d)	$ 4,205,570	
Total Contract System Cost	**$ 424,458,879**	
Contract System Load (MWh)		6.64
Total Retail Load	8,787,002	
(Less) New Large Single Load	61,449	
Total Retail Load (Net of NLSL) (d)	8,725,553	
Distribution Loss (f)	460,439	
Total Contract System Load	**9,185,992**	
Average System Cost $/MWh	**46.21**	

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15H: Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	8,032,540
Transmission	354-355	1,996,647
Distribution	354-355	5,300,368
Customer Accounts	354-355	5,329,149
Customer Service and Information	354-355	300,182
Sales	354-355	428,000
Administrative and General	354-355	11,299,946
TOTAL Operation		**$32,686,832**
Maintenance		
Production	354-355	2,494,282
Transmission	354-355	672,562
Distribution	354-355	4,558,361
Administrative and General	354-355	0
TOTAL Maintenance		**$7,725,205**
Operation and Maintenance		
Production (Total of lines 16 and 26)	354-355	10,526,822
Transmission (Total of lines 17 and 27)	354-355	2,669,209
Distribution (Total of lines 18 and 28)	354-355	9,858,729
Customer Accounts (From line 20)	354-355	5,329,149
Customer Service and Information (From line 20)	354-355	300,182
Sales (From line 21)	354-355	428,000
Administrative and General (Total of lines 22 and 29)	354-355	11,299,946
TOTAL Operation and Maintenance		**$40,412,037**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	**Avista Utilities**
End of Year Report Period:	**12/31/2006**
ASC Filing Date:	**5/7/2008**

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15I: Ratio Table

Labor Ratio Input:	Ratio Used	Total	Production	Transmission	Distribution
Production	PROD	$ 10,526,822	$ 10,526,822	$ -	$ -
Transmission	TRANS	2,669,209	-	2,669,209	-
Distribution	DIST	9,858,729	-	-	9,858,729
Customer Accounts	DIST	5,329,149	-	-	5,329,149
Customer Service and Informational	DIRECT	300,182	264,349	-	35,833
Sales	DIST	428,000	-	-	428,000
Administrative & General	PTD	11,299,946	5,076,396	1,964,562	4,258,988
Total Labor		$ 40,412,037	$ 15,867,567	$ 4,633,771	$ 19,910,699
LABOR RATIO		**100%**	**39%**	**11%**	**49%**

GP General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
Land and Land Rights	PTD	$ 124,681	$ 56,012	$ 21,677	$ 46,993
Structures and Improvements	PTD	2,042,518	917,582	355,104	769,832
Furniture and Equipment	LABOR	136,601	53,636	15,663	67,302
Transportation Equipment	TD	8,275,752	-	2,612,372	5,663,380
Stores Equipment	PTD	120,561	54,161	20,960	45,440
Tools and Garage Equipment	PTD	2,988,365	1,342,495	519,545	1,126,325
Laboratory Equipment	PTD	3,039,673	1,365,545	528,465	1,145,663
Power Operated Equipment	TD	19,674,347	-	6,210,519	13,463,828
Communication Equipment	PTD	28,330,864	12,727,377	4,925,487	10,677,999
Miscellaneous Equipment	PTD	3,973	1,785	691	1,497
Other Tangible Property	DIRECT	-	-	-	-
Asset Retirement Costs for General Plant	PTD	-	-	-	-
TOTAL		$ 64,737,335	$ 16,518,593	$ 15,210,483	$ 33,008,260
GENERAL PLANT RATIO		**100%**	**26%**	**23%**	**51%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

***TABLE 15I*: Ratio Table**

		Ratio Used	Total	Production	Transmission	Distribution
PTD	**Production, Transmission, Distribution Ratio**					
	Steam Production	PROD	$ 378,625,101	$ 378,625,101	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	340,480,980	340,480,980	-	-
	Other Production	PROD	272,688,068	272,688,068	-	-
	Total Production Plant		991,794,149	991,794,149	-	-
	Transmission Plant	TRANS	383,823,745	-	383,823,745	-
	Total Distribution Plant	DIST	832,094,240	-	-	832,094,240
	TOTAL		$ 2,207,712,134	$ 991,794,149	$ 383,823,745	$ 832,094,240
	PTD RATIO		**100%**	**45%**	**17%**	**38%**

		Ratio Used	Total	Production	Transmission	Distribution
PTDG	**Production, Transmission, Distribution and General Plant Ratio**					
	PTD Total		$ 2,207,712,134	$ 991,794,149	$ 383,823,745	$ 832,094,240
	Intangible Plant - Organization	DIST	-	-	-	-
	Intangible Plant - Franchises and Consents	DIRECT	15,259,132	14,889,662	369,470	-
	Intangible Plant - Miscellaneous	DIRECT	4,420,269	-	1,517,348	2,902,921
	General Plant Total		64,737,335	16,518,593	15,210,483	33,008,260
	TOTAL		$ 2,292,128,870	$ 1,023,202,404	$ 400,921,046	$ 868,005,421
	PTDG RATIO		**100%**	**45%**	**17%**	**38%**

		Ratio Used	Total	Production	Transmission	Distribution
TD	**Transmission and Distribution Plant Ratio**					
	Total Transmission Plant	TRANS	$ 383,823,745	$ -	$ 383,823,745	$ -
	Total Distribution Plant	DIST	832,094,240	-	-	832,094,240
	TOTAL		$ 1,215,917,985	$ -	$ 383,823,745	$ 832,094,240
	TD RATIO		**100%**	**0%**	**32%**	**68%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	Avista Utilities
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 15I: Ratio Table

GPM	Maintenance of General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Structures and Improvements	PTD	$ 2,042,518	$ 917,582	$ 355,104	$ 769,832
	Furniture and Equipment	LABOR	136,601	53,636	15,663	67,302
	Communication Equipment	PTD	28,330,864	12,727,377	4,925,487	10,677,999
	Miscellaneous Equipment	PTD	3,973	1,785	691	1,497
	TOTAL		$ 30,513,956	$ 13,700,380	$ 5,296,945	$ 11,516,631
	GPM RATIO		**100%**	**45%**	**17%**	**38%**

SUMMARY RATIO TABLE

Direct to Distribution	**DIST**	**0.00%**	**0.00%**	**100.00%**
Direct to Production	**PROD**	**100.00%**	**0.00%**	**0.00%**
Direct to Transmission	**TRANS**	**0.00%**	**100.00%**	**0.00%**
Direct Allocation	**DIRECT**	**0.00%**	**0.00%**	**0.00%**
General Plant	**GP**	**25.52%**	**23.50%**	**50.99%**
Maintenance of General Plant	**GPM**	**44.90%**	**17.36%**	**37.74%**
Labor Ratios	**LABOR**	**39.26%**	**11.47%**	**49.27%**
Production, Transmission, Distribution	**PTD**	**44.92%**	**17.39%**	**37.69%**
Production, Transmission, Distribution, General	**PTDG**	**44.64%**	**17.49%**	**37.87%**
Transmission, Distribution	**TD**	**0.00%**	**31.57%**	**68.43%**

BONNEVILLE POWER ADMINSTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

TABLE 15J

UTILITY NAME: Avista Utilities
End of Year Report Period: 12/30/2006
ASC Filing Date: 5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

FERC Form 1 Statistical Classification	Page Number	Purchased Power - Base Period Settlement Total	Purchased Power - Base Period MWh Purchased	Purchased Power - Base Period Minus 1 Settlement Total	Purchased Power - Base Period Minus 1 MWh Purchased	Purchased Power - Base Period Minus 2 Settlement Total	Purchased Power - Base Period Minus 2 MWh Purchased
RQ	326-327	$ 6,183	124	$ 4,860	38	$ 4,111	-
LF	326-327	$ 12,903,902	362,075	$ 11,877,298	457,836	$ 12,749,802	438,391
IF	326-327	$ 26,191,912	878,284	$ 26,266,566	882,372	$ 26,271,191	885,731
SF	326-327	$ 113,803,605	2,418,310	$ 180,444,332	3,148,858	$ 93,694,368	2,144,927
LU	326-327	$ 41,336,441	1,627,926	$ 34,971,204	1,494,022	$ 35,078,323	1,447,477
IU	326-327	$ 1,532,242	36,513	$ 1,410,830	36,846	$ 1,525,477	37,797
OS	326-327	$ 702,316	-	$ 18,276		$ 15,218	
EX	326-327	$ 3,606,618	-	$ 2,084,254		$ 2,535,605	560
NA	326-327						
AD	326-327						
TOTAL		**$ 200,083,219**	**5,323,232**	**$ 257,077,620**	**6,019,972**	**$ 171,874,095**	**4,954,883**

FERC Form 1 Statistical Classification	Page Number	Sales for Resale - Base Period Settlement Total	Sales for Resale - Base Period MWh Sold	Sales for Resale - Base Period Minus 1 Settlement Total	Sales for Resale - Base Period Minus 1 MWh Sold	Sales for Resale - Base Period Minus 2 Settlement Total	Sales for Resale - Base Period Minus 2 MWh Sold
RQ	310-311						
LF	310-311	$ 9,039,526	122,445	$ 5,272,397	57,573	$ 4,119,289	55,225
IF	310-311	$ 3,449,688	32,833	$ 990,341	8,128	$ 1,229,175	16,235
SF	310-311	$ 163,105,424	3,397,421	$ 215,537,447	4,078,716	$ 84,652,780	2,161,327
LU	310-311						
IU	310-311						
OS	310-311						
EX	310-311						
NA	310-311						
AD	310-311						
TOTAL		**$ 175,594,638**	**3,552,699**	**$ 221,800,185**	**4,144,417**	**$ 90,001,244**	**2,232,787**

AVISTA - TABLE 15K **Forecasted Contract System Costs & ASC with New Additions and NLSL**

Date	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
	7	8	9	10	11
Fiscal Year	2009	2010	2011	2012	2013
Rate Period Mid-Point	**TRUE**	**FALSE**	**FALSE**	**FALSE**	**FALSE**
Contract System Cost					
Production	426,553,083	418,576,017	429,968,037	438,593,985	447,787,283
Transmission	60,000,388	59,329,051	58,710,865	58,065,786	57,450,436
NLSL Fully Allocated Cost ($/MWh)	77.64	71.88	72.36	70.98	69.95
(Less) New Large Single Load Costs (d)	**4,771,005**	**4,416,922**	**4,446,260**	**4,361,813**	**4,298,313**
Total Contract System Cost	481,782,465	473,488,147	484,232,641	492,297,957	500,939,406
Contract System Load (MWh)					
Total Retail Load @ Meter	9,163,546	9,349,910	9,508,840	9,709,299	9,890,789
(Less) New Large Single Load	**61,449**	**61,449**	**61,449**	**61,449**	**61,449**
Total Retail Load (Net of NLSL) (d)	9,102,097	9,288,461	9,447,391	9,647,850	9,829,340
Distribution Loss (f)	480,170	489,935	498,263	508,767	518,277
Total Contract System Load	9,582,267	9,778,396	9,945,654	10,156,617	10,347,617
Average System Cost $/MWh	**50.28**	**48.42**	**48.69**	**48.47**	**48.41**

	Rate Period Mid-Point
Date	**4/1/09**
Fiscal Year	2009
NLSL Switch	1
Contract System Cost	
Production	426,553,083
Transmission	60,000,388
(Less) New Large Single Load Costs (d)	4,771,005
Total Contract System Cost	481,782,465
Contract System Load (MWh)	
Total Retail Load @ Meter	9,163,546
(Less) New Large Single Load	**61,449**
Total Retail Load (Net of NLSL) (d)	9,102,097
Distribution Loss (f)	480,170
Total Contract System Load	9,582,267
Average System Cost $/MWh	**50.28**

Tables for:

Centralia City Light

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Centralia City Light	
End of Year Report Period:	2006	Revised 6/25/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 16A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST			-	-	-
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD	4,862,082	4,862,082		
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST				
Total Intangible Plant					**$ 4,862,082**	**$ 4,862,082**	**$ -**	**$ -**
Production Plant:								
Steam Production	204-207	310-317	PROD				-	-
Nuclear Production	204-207	320-326	PROD			-	-	-
Hydraulic Production	204-207	330-337	PROD		17,347,340	17,347,340	-	-
Other Production	204-207	340-347	PROD				-	-
Total Production Plant					**$ 17,347,340**	**$ 17,347,340**	**$ -**	**$ -**
Transmission Plant: (i)								
Transmission Plant	204-207	350-359.1	TRANS		1,254,542	-	1,254,542	-
Total Transmission Plant					**$ 1,254,542**	**$ -**	**$ 1,254,542**	**$ -**
Distribution Plant:								
Distribution Plant	204-207	360-374	DIST		18,412,707	-	-	18,412,707
Total Distribution Plant					**$ 18,412,707**	**$ -**	**$ -**	**$ 18,412,707**
General Plant:								
Land and Land Rights	204-207	389	PTD		16,462	7,715	558	8,189
Structures and Improvements	204-207	390	PTD		380,460	178,307	12,895	189,258
Furniture and Equipment	204-207	391	LABOR		12,379	3,448	1,350	7,581
Transportation Equipment	204-207	392	TD		1,237,871	-	78,962	1,158,909
Stores Equipment	204-207	393	PTD					
Tools and Garage Equipment	204-207	394	PTD		60,531	28,369	2,052	30,111
Laboratory Equipment	204-207	395	PTD					
Power Operated Equipment	204-207	396	TD		174,115	-	11,107	163,008
Communication Equipment	204-207	397	PTD					
Miscellaneous Equipment	204-207	398	PTD					
Other Tangible Property	204-207	399	DIRECT	PTD		-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD			-	-	-
Total General Plant					**$ 1,881,818**	**$ 217,839**	**$ 106,923**	**$ 1,557,056**
Total Electric Plant In-Service					**$ 43,758,489**	**$ 22,427,261**	**$ 1,361,465**	**$ 19,969,763**

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Centralia City Light	
End of Year Report Period:	2006	Revised 6/25/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 16A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD					
Nuclear Production Plant	219	108	PROD					
Hydraulic Production Plant	219	108	PROD		5,732,720	5,732,720	-	-
Other Production Plant	219	108	PROD					
Transmission Plant (i)	219	108	TRANS		1,004,036	-	1,004,036	-
Distribution Plant	219	108	DIST		6,426,691	-	-	6,426,691
General Plant	219	108	GP		735,757	85,171	41,805	608,781
Amortization of Intangible Plant - Account 301	219	111	DIST			-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD	1,000,544	1,000,544	-	-
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST		-	-	-
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	111	DIST			-	-	-
Capital Lease - Common Plant	219	108	DIRECT			-	-	-
Leasehold Improvements	200-201	108	DIRECT	DIST		-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT			-	-	-
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST		-	-	-
Amortization of Acquisition Adjustments	200-201	115	DIST			-	-	-
Depreciation and Amortization Reserve (Other)			DIRECT					
Total Depreciation and Amortization Reserve					$ 14,899,748	$ 6,818,435	$ 1,045,841	$ 7,035,472
Total Net Plant					$ 28,858,741	$ 15,608,826	$ 315,624	$ 12,934,291
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Centralia City Light	
End of Year Report Period:	2006	Revised 6/25/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 16A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation: Automatic Input from Sch 1A				654,026	141,093	160,810	352,123
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST			-	-	-
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD			-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST		4,098,931	-	-	4,098,931
Common Plant	356 & 356.1		DIRECT					
Acquisition Adjustments (Electric)	200-201	114	DIST	DIST		-	-	-
Total					**$ 4,098,931**	**$ -**	**$ -**	**$ 4,098,931**
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST		-	-	-
Other Investment	110-111	124	DIST			-	-	-
Long-Term Portion of Derivative Assets	110-111	175	DIST			-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST			-	-	-
Total					**$ -**	**$ -**	**$ -**	**$ -**
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD			-	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD			-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD		404,389	189,522	13,706	201,161
Merchandise (Major Only)	110-112	155	DIST			-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST			-	-	-
EPA Allowance Inventory	110-112	158.1	PROD			-	-	-
EPA Allowances Withheld	110-112	158.2	PROD			-	-	-
Stores Expense Undistributed	110-111	163	PTD			-	-	-
Prepayments	110-111	165	PTD			-	-	-
Derivative Instrument Assets	110-111	175	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST			-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST			-	-	-
Total					**$ 404,389**	**$ 189,522**	**$ 13,706**	**$ 201,161**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Centralia City Light	
End of Year Report Period:	2006	Revised 6/25/2008 REB BPA
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TABLE 16A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG		87,488	44,840	2,722	39,926
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST		-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST		-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST		-	-	-
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST			-	-	-
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST			-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST			-	-	-
Clearing Accounts	110-111	184	DIST			-	-	-
Temporary Facilities	110-111	185	PTDG			-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST		-	-	-
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT					
Research, Development, and Demonstration Expenditures	110-111	188	DIST			-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG			-	-	-
Accumulated Deferred Income Taxes	110-111	190	DIST			-	-	-
Total					**$ 87,488**	**$ 44,840**	**$ 2,722**	**$ 39,926**
Total Assets and Other Debits					**$ 5,244,834**	**$ 375,455**	**$ 177,238**	**$ 4,692,141**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

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TABLE 16A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Liabilities and Other Credits (Comparative Balance Sheet)								
CURRENT AND ACCRUED LIABILITIES								
Derivative Instrument Liabilities	112-113	244	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST			-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
DEFERRED CREDITS								
Customer Advances for Construction	112-113	252	DIST			-	-	-
Other Deferred Credits	112-113	253	DIRECT	DIST		-	-	-
Other Regulatory Liabilities	112-113	254	DIRECT	DIST		-	-	-
Accumulated Deferred Investment Tax Credits	112-113	255	DIST			-	-	-
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT					
Unamortized Gain on Reacquired Debt	112-113	257	PTDG			-	-	-
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST			-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST			-	-	-
Accumulated Deferred Income Taxes-Other	112-113	283	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Total Liabilities and Other Credits					$ -	$ -	$ -	$ -
Total Rate Base					$ 34,103,575	$ 15,984,280	$ 492,862	$ 17,626,433
Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)								

BONNEVILLE POWER ADMINISTRATION
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Proposed 2008 Average System Cost Methodology

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TABLE 16B: Schedule 1A: Cash Working Capital (f)
(Automatic Input from Schedule 3- Expenses)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	6,501,441	6,501,441	-	-
Total Transmission O&M (i)	1,170,940	-	1,170,940	-
Total Distribution O&M	1,749,923	-	-	1,749,923
Total Customer & Sales	418,514	-	-	418,514
Total Administrative and General O&M	1,059,046	294,963	115,536	648,547
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	5,667,659	5,667,659	-	-
Revised Total O&M Expenses	**$ 5,232,205**	**$ 1,128,745**	**$ 1,286,476**	**$ 2,816,984**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 654,026**	**$ 141,093**	**$ 160,810**	**$ 352,123**

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TABLE 16C: Schedule 2: Capital Structure and Rate of Return (b)

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:	
Multi-Jurisdiction Investor-Owned Utility Return Calculation:	
Consumer-Owned Utility Return Calculation:	4.650%
Rate of Return :	**4.650%**

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order

Note: Multi-jurisdictional utilities must begin on Page 2
Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**
Debt				
Preferred Equity				
Common Equity				
Weighted Cost of Capital	$ -			

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) **35%**

Federal Income Tax Factor

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 34,103,575	$ 15,984,280	$ 492,862	$ 17,626,433
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

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TABLE 16C: Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation

Step 1:

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 1

	Capitalization Structure		Effective Cost		Jurisdictional	Effective Cost -	
Component	Amount	Percent	Embedded	Weighted	Allocation	Weighted State Allocation	
Debt							
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 2

Component	Amount	Percent	Embedded	Weighted			
Debt					5.00%		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 3

Component	Amount	Percent	Embedded	Weighted			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Jurisdiction	Rate Base	Weighted cost	%	Weighted Return		
Idaho						
Oregon						
Total					5.00%	

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TABLE 16C: Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation *(continued)*

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) **35%**

Federal Income Tax Factor

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 34,103,575	$ 15,984,280	$ 492,862	$ 17,626,433
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				
*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*				

BONNEVILLE POWER ADMINISTRATION

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TABLE 16C: Schedule 2: Capital Structure and Rate of Return (b)

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

Debt Issue	Original Amount	Year Issued	Year Due	Interest Rate	Interest Expense
1999 Revenue Bonds	$ 7,460,000				$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	**$ 7,460,000**				**$ -**

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 34,103,575	$ 15,984,280	$ 492,862	$ 17,626,433
Weighted Cost of Debt	4.65%	4.65%	4.65%	4.65%
Return on Rate Base	**$1,585,816**	**$743,269**	**$22,918**	**$819,629**

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TABLE 16D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD			-	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD			-	-	-
Steam Power - Maintenance	320-323	510-515	PROD			-	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD			-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD			-	-	-
Nuclear - Maintenance	320-323	528-532	PROD			-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD		742,823	742,823	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD		90,959	90,959	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD			-	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD			-	-	-
Other Power - Maintenance	320-323	551-554.1	PROD			-	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	320-323	555	PROD		5,667,659	5,667,659	-	-
System Control and Load Dispatching	320-323	556	PROD			-	-	-
Other Expenses	320-323	557	PROD			-	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (h)			DIRECT					
Total Production Expense					**$ 6,501,441**	**$ 6,501,441**	**$ -**	**$ -**
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS		948,236	-	948,236	-
Total Operations less Wheeling	320-323	560-567.1	TRANS		113,202	-	113,202	-
Total Maintenance	320-323	568-574	TRANS		109,502	-	109,502	-
Total Transmission Expense					**$ 1,170,940**	**$ -**	**$ 1,170,940**	**$ -**

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TABLE 16D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Distribution Expense:								
Total Operations	320-323	580-589	DIST		1,387,327	-	-	1,387,327
Total Maintenance	320-323	590-598	DIST		362,596	-	-	362,596
Total Distribution Expense					$ 1,749,923	$ -	$ -	$ 1,749,923
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST		299,350	-	-	299,350
Customer Service and Information	320-323	906-907	DIST		119,164	-	-	119,164
Customer Assistance Expenses (Major only)	320-323	908	DIRECT			-	-	-
Customer Service and Information	320-323	909-910	DIST			-	-	-
Total Sales Expense	320-323	911-917	DIST			-	-	-
Total Customer and Sales Expenses					$ 418,514	$ -	$ -	$ 418,514
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR		826,091	230,081	90,122	505,888
Office Supplies & Expenses	320-323	921	LABOR		1,643	458	179	1,006
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR			-	-	-
Outside Services Employed	320-323	923	LABOR		231,312	64,424	25,235	141,653
Property Insurance	320-323	924	PTDG			-	-	-
Injuries and Damages	320-323	925	LABOR			-	-	-
Employee Pensions & Benefits	320-323	926	LABOR			-	-	-
Franchise Requirements	320-323	927	DIST			-	-	-
Regulatory Commission Expenses	320-323	928	DIST			-	-	-
(Less) Duplicate Charges - Credit	320-323	929	PTDG			-	-	-
General Advertising Expenses	320-323	930.1	DIST	DIST		-	-	-
Miscellaneous General Expenses	320-323	930.2	DIST			-	-	-
Rents	320-323	931	DIST			-	-	-
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM			-	-	-
Total Administration and General Expenses					$ 1,059,046	$ 294,963	$ 115,536	$ 648,547

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TABLE 16D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Total Operations and Maintenance					$ 10,899,864	$ 6,796,404	$ 1,286,476	$ 2,816,984
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD	121,939	121,939	-	-
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST		-	-	-
Steam Production Plant	336	403	PROD			-	-	-
Nuclear Production Plant	336	403	PROD			-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD		315,475	315,475	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD			-	-	-
Other Production Plant	336	403	PROD			-	-	-
Transmission Plant (i)	336	403	TRANS		12,002	-	12,002	-
Distribution Plant	336	403	DIST		429,900	-	-	429,900
General Plant	336	403	GP		116,636	13,502	6,627	96,507
Common Plant - Electric	336	403	DIRECT					
Common Plant - Electric	336	404	DIRECT					
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT					
Amortization of Limited Term Electric Plant	336	404	DIRECT					
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIST					
Total Depreciation and Amortization					$ 995,952	$ 450,916	$ 18,629	$ 526,407
Total Operating Expenses					$ 11,895,816	$ 7,247,319	$ 1,305,105	$ 3,343,391
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

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TABLE 16E: Schedule 3A Items: Taxes (Including Income Taxes)

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Funct. Method	Total	Production	Transmission	Distribution/ Other
FEDERAL							
Income Tax (Included on Schedule 2)	262	409.1	DIST		-	-	-
Employment Tax	262	408.1	LABOR		-	-	-
Other Federal Taxes	262	408.1	DIST		-	-	-
TOTAL FEDERAL				$ -	$ -	$ -	$ -
STATE AND OTHER							
Property	262	408.1	PTDG		-	-	-
Unemployment	262	408.1	LABOR		-	-	-
State Income, B&O, et.	262	409.1	DIST	546,959	-	-	546,959
Franchise Fees	262	408.1	DIST		-	-	-
Regulatory Commission	262	408.1	DIST		-	-	-
City/Municipal	262	408.1	DIST	899,071	-	-	899,071
Other	262	408.1	DIST		-	-	-
TOTAL STATE AND OTHER TAXES				**$ 1,446,030**	$ -	$ -	**$ 1,446,030**
TOTAL TAXES				**$ 1,446,030**	$ -	$ -	**$ 1,446,030**

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TABLE 16F: Schedule 3B Other Included Items

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD		-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST		-	-	-
Gain from Disposition of Utility Plant	114	411.6	DIRECT	PROD	1,779	-	-	1,779
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST		-	-	-
Gain from Disposition of Allowances	114	411.8	PROD			-	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD			-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD		-	-	-
Total Other Included Items					$ 1,779	$ -	$ -	$ 1,779
Sales for Resale:								
Sales for Resale	310	447	PROD		-	-	-	-
Total Sales for Resale					$ -	$ -	$ -	$ -
Other Revenues:								
Forfeited Discounts	300	450	DIST			-	-	-
Miscellaneous Service Revenues	300	451	DIST			-	-	-
Sales of Water and Water Power	300	453	PROD			-	-	-
Rent from Electric Property	300	454	TD		63,114	-	4,026	59,088
Interdepartmental Rents	300	455	DIST			-	-	-
Other Electric Revenues	300	456	DIRECT	PROD	135,834	45,229	-	90,605
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS			-	-	-
Total Other Revenues					$ 198,948	$ 45,229	$ 4,026	$ 149,693
Total Other Included Items					$ 200,727	$ 45,229	$ 4,026	$ 151,472

(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)

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TABLE 16G: Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses	$ 11,895,816	$ 7,247,319	$ 1,305,105	$ 3,343,391
(From Schedule 3)				
Federal Income Tax Adjusted Return on Rate Base	$ 1,585,816	$ 743,269	$ 22,918	$ 819,629
(From Schedule 2)				
State and Other Taxes	$ 1,446,030	$ -	$ -	$ 1,446,030
(From Schedule 3a)				
Total Other Included Items	$ 200,727	$ 45,229	$ 4,026	$ 151,472
(From Schedule 3b)				
Total Cost	**$ 14,726,935**	**$ 7,945,359**	**$ 1,323,997**	**$ 5,457,578**

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

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TABLE 16G: Schedule 4: Average System Cost

Contract System Cost	
Production	$ 7,945,359
Transmission	$ 1,323,997
(Less) New Large Single Load Costs (d)	
Total Contract System Cost	**$ 9,269,357**
Contract System Load (MWh)	
Total Retail Load	234,779
(Less) New Large Single Load	
Total Retail Load (Net of NLSL) (d)	234,779
Distribution Loss (f)	11,739
Total Contract System Load	**246,518**
Average System Cost $/MWh	**37.60**

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TABLE 16H: Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	584,419
Transmission	354-355	112,902
Distribution	354-355	969,587
Customer Accounts	354-355	246,266
Customer Service and Information	354-355	52,441
Sales	354-355	
Administrative and General	354-355	77,415
TOTAL Operation		**$2,043,030**
Maintenance		
Production	354-355	51,109
Transmission	354-355	147,620
Distribution	354-355	170,333
Administrative and General	354-355	
TOTAL Maintenance		**$369,062**
Operation and Maintenance		
Production (Enter Total of lines 1 and 9)	354-355	635,528
Transmission (Enter Total of lines 2 and 10)	354-355	260,522
Distribution (Enter Total of lines 3 and 11)	354-355	1,139,920
Customer Accounts (Transcribe from line 4)	354-355	246,266
Customer Service and Information (Transcribe from line 5)	354-355	52,441
Sales (Transcribe from line 6)	354-355	
Administrative and General (Enter Total of lines 7 and 12)	354-355	77,415
TOTAL Operation and Maintenance		**$2,412,092**

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TABLE 16I: Ratio Table

Labor Ratio Input:	Ratio Used	Total	Production	Transmission	Distribution
Production	PROD	$ 635,528	$ 635,528	$ -	$ -
Transmission	TRANS	260,522	-	260,522	-
Distribution	DIST	1,139,920	-	-	1,139,920
Customer Accounts	DIST	246,266	-	-	246,266
Customer Service and Informational	DIRECT	52,441	-	-	52,441
Sales	DIST	-	-	-	-
Administrative & General	PTD	77,415	36,281	2,624	38,510
Total Labor		$ 2,412,092	$ 671,809	$ 263,146	$ 1,477,137
LABOR RATIO		**100%**	**28%**	**11%**	**61%**

GP **General Plant Ratio**	Ratio Used	Total	Production	Transmission	Distribution
Land and Land Rights	PTD	$ 16,462	$ 7,715	$ 558	$ 8,189
Structures and Improvements	PTD	380,460	178,307	12,895	189,258
Furniture and Equipment	LABOR	12,379	3,448	1,350	7,581
Transportation Equipment	TD	1,237,871	-	78,962	1,158,909
Stores Equipment	PTD	-	-	-	-
Tools and Garage Equipment	PTD	60,531	28,369	2,052	30,111
Laboratory Equipment	PTD	-	-	-	-
Power Operated Equipment	TD	174,115	-	11,107	163,008
Communication Equipment	PTD	-	-	-	-
Miscellaneous Equipment	PTD	-	-	-	-
Other Tangible Property	DIRECT	-	-	-	-
Asset Retirement Costs for General Plant	PTD	-	-	-	-
TOTAL		$ 1,881,818	$ 217,839	$ 106,923	$ 1,557,056
GP RATIO		**100%**	**12%**	**6%**	**83%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Centralia City Light	
End of Year Report Period:	12/31/2006	Revised 6/25/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 16I: Ratio Table

PTD	Production, Transmission, Distribution Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Steam Production	PROD	$ -	$ -	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	17,347,340	17,347,340	-	-
	Other Production	PROD	-	-	-	-
	Total Production Plant		17,347,340	17,347,340	-	-
	Transmission Plant	TRANS	1,254,542	-	1,254,542	-
	Total Distribution Plant	DIST	18,412,707	-	-	18,412,707
	TOTAL		$ 37,014,589	$ 17,347,340	$ 1,254,542	$ 18,412,707
	PTD RATIO		100%	47%	3%	50%

PTDG	Production, Transmission, Distribution and General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	PTD Total		$ 37,014,589	$ 17,347,340	$ 1,254,542	$ 18,412,707
	Intangible Plant - Organization	DIST	-	-	-	-
	Intangible Plant - Franchises and Consents	DIRECT	4,862,082	4,862,082	-	-
	Intangible Plant - Miscellaneous	DIRECT	-	-	-	-
	General Plant Total		1,881,818	217,839	106,923	1,557,056
	TOTAL		$ 43,758,489	$ 22,427,261	$ 1,361,465	$ 19,969,763
	PTDG RATIO		100%	51%	3%	46%

TD	Transmission and Distribution Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Total Transmission Plant	TRANS	$ 1,254,542	$ -	$ 1,254,542	$ -
	Total Distribution Plant	DIST	18,412,707	-	-	18,412,707
	TOTAL		$ 19,667,249	$ -	$ 1,254,542	$ 18,412,707
	TD RATIO		100%	0%	6%	94%

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Centralia City Light	
End of Year Report Period:	12/31/2006	Revised 6/25/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 16I: Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
GPM	**Maintenance of General Plant Ratio**					
	Structures and Improvements	PTD	$ 380,460	$ 178,307	$ 12,895	$ 189,258
	Furniture and Equipment	LABOR	12,379	3,448	1,350	7,581
	Communication Equipment	PTD	-	-	-	-
	Miscellaneous Equipment	PTD	-	-	-	-
	TOTAL		$ 392,839	$ 181,755	$ 14,245	$ 196,839
	GPM RATIO		100%	46%	4%	50%

SUMMARY RATIO TABLE

Direct to Distribution	DIST	0.00%	0.00%	100.00%
Direct to Production	PROD	100.00%	0.00%	0.00%
Direct to Transmission	TRANS	0.00%	100.00%	0.00%
Direct Allocation	DIRECT	0.00%	0.00%	0.00%
General Plant	GP	11.58%	5.68%	82.74%
Maintenance of General Plant	GPM	46.27%	3.63%	50.11%
Labor Ratios	LABOR	27.85%	10.91%	61.24%
Production, Transmission, Distribution	PTD	46.87%	3.39%	49.74%
Production, Transmission, Distribution, General	PTDG	51.25%	3.11%	45.64%
Transmission, Distribution	TD	0.00%	6.38%	93.62%

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

TABLE 16J

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Centralia City Light
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Revised 6/25/2008 REB BPA

Amended Revised 8/4/08

Purchased Power & Off-System Sales

FERC Form 1		Purchased Power	
Statistical Classification	Page Number	Settlement Total	MWh Purchased
RQ	326-327	$ 5,667,659	181,005
LF	326-327		
IF	326-327		
SF	326-327		
LU	326-327		
IU	326-327		
OS	326-327		
EX	326-327		
NA	326-327		
AD	326-327		
TOTAL		**$ 5,667,659**	**181,005**

FERC Form 1		Sales for Resale	
Statistical Classification	Page Number	Settlement Total	MWh Purchased
RQ	310-311		
LF	310-311		
IF	310-311		
SF	310-311		
LU	310-311		
IU	310-311		
OS	310-311		
EX	310-311		
NA	310-311		
AD	310-311		
TOTAL		$ -	-

CENTRALIA **TABLE 16K: Forecasted Contract system Costs & ASC with New Additions and NLSL**

Date	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
	6	7	8	9	10
Fiscal Year	2009	2010	2011	2012	2013
Rate Period Mid-Point	**TRUE**	**FALSE**	**FALSE**	**FALSE**	**FALSE**
Contract System Cost					
Production	8,931,977	9,508,022	9,740,887	10,495,488	10,753,858
Transmission	1,410,451	1,434,131	1,461,501	1,489,785	1,519,456
NLSL Fully Allocated Cost ($/MWh)					
(Less) New Large Single Load Costs (d)	**0**	**0**	**0**	**0**	**0**
Total Contract System Cost	10,342,428	10,942,154	11,202,389	11,985,273	12,273,314
Contract System Load (MWh)					
Total Retail Load @ Meter	276,991	283,912	290,833	298,227	305,531
(Less) New Large Single Load	**0**	**0**	**0**	**0**	**0**
Total Retail Load (Net of NLSL) (d)	276,991	283,912	290,833	298,227	305,531
Distribution Loss (f)	13,850	14,196	14,542	14,911	15,277
Total Contract System Load	290,840	298,108	305,375	313,138	320,808
Average System Cost $/MWh	**35.56**	**36.71**	**36.68**	**38.27**	**38.26**

	Rate Period Mid-Point
Date	**4/1/09**
Fiscal Year	2009
NLSL Switch	0
Contract System Cost	
Production	8,931,977
Transmission	1,410,451
(Less) New Large Single Load Costs (d)	0
Total Contract System Cost	10,342,428
Contract System Load (MWh)	
Total Retail Load @ Meter	276,991
(Less) New Large Single Load	**0**
Total Retail Load (Net of NLSL) (d)	276,991
Distribution Loss (f)	13,850
Total Contract System Load	290,840
Average System Cost $/MWh	**35.56**

Tables for:

Franklin County PUD

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME: **PUD No. 1 of Franklin County**
End of Year Report Period: **2006** — Amended BPA: 7-8-2008
ASC Filing Date: **5/7/2008** — Revised Amended BPA: 8-4-2008

TABLE 17A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST			-	-	-
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD		-	-	-
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST		-	-	-
Total Intangible Plant					$ -	$ -	$ -	$ -
Production Plant:								
Steam Production	204-207	310-317	PROD			-	-	-
Nuclear Production	204-207	320-326	PROD			-	-	-
Hydraulic Production	204-207	330-337	PROD			-	-	-
Other Production	204-207	340-347	PROD		18,232,751	18,232,751	-	-
Total Production Plant					$ 18,232,751	$ 18,232,751	$ -	$ -
Transmission Plant: (i)								
Transmission Plant	204-207	350-359.1	TRANS		3,971,116	-	3,971,116	-
Total Transmission Plant					$ 3,971,116	$ -	$ 3,971,116	$ -
Distribution Plant:								
Distribution Plant	204-207	360-374	DIST		89,849,816	-	-	89,849,816
Total Distribution Plant					$ 89,849,816	$ -	$ -	$ 89,849,816
General Plant:								
Land and Land Rights	204-207	389	PTD		128,960	20,984	4,570	103,406
Structures and Improvements	204-207	390	PTD		5,222,950	849,849	185,098	4,188,002
Furniture and Equipment	204-207	391	LABOR		3,856,888	378,758	43,683	3,434,447
Transportation Equipment	204-207	392	TD		2,793,281	-	118,230	2,675,051
Stores Equipment	204-207	393	PTD		20,788	3,383	737	16,669
Tools and Garage Equipment	204-207	394	PTD		730,593	118,878	25,892	585,823
Laboratory Equipment	204-207	395	PTD		25,767	4,193	913	20,661
Power Operated Equipment	204-207	396	TD		6,521	-	276	6,245
Communication Equipment	204-207	397	PTD		8,934,819	1,453,824	316,645	7,164,350
Miscellaneous Equipment	204-207	398	PTD		262,763	42,755	9,312	210,696
Other Tangible Property	204-207	399	PTD	PTD	1,237,870	201,419	43,869	992,581
Asset Retirement Costs for General Plant	204-208	399.1	PTD			-	-	-
Total General Plant					$ 23,221,200	$ 3,074,043	$ 749,225	$ 19,397,932
Total Electric Plant In-Service					$ 135,274,883	$ 21,306,794	$ 4,720,341	$ 109,247,748

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	PUD No. 1 of Franklin County	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 17A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD			-	-	-
Nuclear Production Plant	219	108	PROD			-	-	-
Hydraulic Production Plant	219	108	PROD			-	-	-
Other Production Plant	219	108	PROD		6,449,441	6,449,441	-	-
Transmission Plant (i)	219	108	TRANS		1,381,217	-	1,381,217	-
Distribution Plant	219	108	DIST		31,873,542	-	-	31,873,542
General Plant	219	108	GP		4,407,478	583,466	142,206	3,681,806
Amortization of Intangible Plant - Account 301	219	111	DIST			-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST		-	-	-
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	111	DIST			-	-	-
Capital Lease - Common Plant	219	108	DIRECT			-	-	-
Leasehold Improvements	200-201	108	DIRECT	DIST		-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT			-	-	-
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST		-	-	-
Amortization of Acquisition Adjustments	200-201	115	DIRECT			-	-	-
Depreciation and Amortization Reserve (Other)			DIRECT					
Total Depreciation and Amortization Reserve					$ 44,111,678	$ 7,032,907	$ 1,523,423	$ 35,555,348
Total Net Plant					$ 91,163,205	$ 14,273,887	$ 3,196,918	$ 73,692,400

(Total Electric Plant In-Service) - (Total Depreciation & Amortization)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME: **PUD No. 1 of Franklin County**
End of Year Report Period: **2006** — Amended BPA: 7-8-2008
ASC Filing Date: **5/7/2008** — Revised Amended BPA: 8-4-2008

TABLE 17A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation				2,050,011	1,052,409	8,048	989,554
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST			-	-	-
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD			-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST		3,799,899	-	-	3,799,899
Common Plant	356 & 356.1		DIRECT					
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST		-	-	-
Total					**$ 3,799,899**	**$ -**	**$ -**	**$ 3,799,899**
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST	145,500	-	-	145,500
Other Investment	110-111	124	DIST		1,995,932	-	-	1,995,932
Long-Term Portion of Derivative Assets	110-111	175	DIST			-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST			-	-	-
Total					**$ 2,141,432**	**$ -**	**$ -**	**$ 2,141,432**
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD			-	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD			-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD		3,878,323	631,059	137,445	3,109,818
Merchandise (Major Only)	110-112	155	DIST			-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST			-	-	-
EPA Allowance Inventory	110-112	158.1	PROD			-	-	-
EPA Allowances Withheld	110-112	158.2	PROD			-	-	-
Stores Expense Undistributed	110-111	163	PTD			-	-	-
Prepayments	110-111	165	PTD		86,044	14,001	3,049	68,994
Derivative Instrument Assets	110-111	175	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST			-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST			-	-	-
Total					**$ 3,964,367**	**$ 645,060**	**$ 140,495**	**$ 3,178,812**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME: **PUD No. 1 of Franklin County**
End of Year Report Period: **2006** — Amended BPA: 7-8-2008
ASC Filing Date: **5/7/2008** — Revised Amended BPA: 8-4-2008

TABLE 17A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG		1,293,260	203,698	45,128	1,044,434
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST		-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST		-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST		-	-	-
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST			-	-	-
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST			-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST			-	-	-
Clearing Accounts	110-111	184	DIST		2,048	-	-	2,048
Temporary Facilities	110-111	185	PTDG			-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST	1,870,145	1,870,145	-	-
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT					
Research, Development, and Demonstration Expenditures	110-111	188	DIST			-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG			-	-	-
Accumulated Deferred Income Taxes	110-111	190	DIST			-	-	-
Total					**$ 3,165,453**	**$ 2,073,843**	**$ 45,128**	**$ 1,046,482**
Total Assets and Other Debits					**$ 15,121,162**	**$ 3,771,311**	**$ 193,670**	**$ 11,156,180**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	PUD No. 1 of Franklin County	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 17A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Liabilities and Other Credits (Comparative Balance Sheet)								
Current and Accrued Liabilites								
Derivative Instrument Liabilities	112-113	244	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST			-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities - He	112-114	245	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Deferred Credits								
Customer Advances for Construction	112-113	252	DIST			-	-	-
Other Deferred Credits	112-113	253	DIRECT	DIST	1,799,931	1,799,931	-	-
Other Regulatory Liabilities	112-113	254	DIRECT	DIST		-	-	-
Accumulated Deferred Investment Tax Credits	112-113	255	DIST			-	-	-
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT					
Unamortized Gain on Reacquired Debt	112-113	257	PTDG			-	-	-
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST			-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST			-	-	-
Accumulated Deferred Income Taxes-Other	112-113	283	DIST			-	-	-
Total					$ 1,799,931	$ 1,799,931	$ -	$ -
Total Liabilities and Other Credits					$ 1,799,931	$ 1,799,931	$ -	$ -
Total Rate Base					$ 104,484,436	$ 16,245,267	$ 3,390,588	$ 84,848,580

Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 17B: Schedule 1A: Cash Working Capital (f)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	56,869,545	56,869,545	-	-
Total Transmission O&M (i)	19,786	-	19,786	-
Total Distribution O&M	2,589,027	-	-	2,589,027
Total Customer & Sales	1,658,581	-	-	1,658,581
Total Administrative and General O&M	4,081,116	367,693	44,595	3,668,828
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel	48,817,968	48,817,968	-	-
Revised Total O&M Expenses	**$ 16,400,087**	**$ 8,419,270**	**$ 64,381**	**$ 7,916,436**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 2,050,011**	**$ 1,052,409**	**$ 8,048**	**$ 989,554**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 17C: Schedule 2: Capital Structure and Rate of Return (b)

Consumer-Owned Utility Return Calculation

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

Step 1: Weighted Cost of Debt

Debt Issue	Original Amount	Year Issued	Year Due	Interest Rate	Interest Expense
1996 Revenues & Refunding Bon	$ 5,100,000	1996	2012	5.0% - 5.5%	$ 242,156
1998 Revenues & Refunding Bon	$ 12,750,000	1998	2018	4.0% - 5.0%	$ 238,040
2001 Revenue & Refunding Bond	$ 19,460,000	2001	2021	3.75% - 5.625%	$ 952,443
2002 Revenue & Refunding Bond	$ 21,705,000	2002	2022	4.0% - 5.625%	$ 1,193,200
2003 Revenue & Refunding Bond	$ 14,630,000	2003	2014	2.0% - 3.25%	$ 321,421
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	**$ 73,645,000**			**4.00%**	**$ 2,947,260**

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 104,484,436	$ 16,245,267	$ 3,390,588	$ 84,848,580
Weighted Cost of Debt	4.002%	4.002%	4.002%	4.002%
Return on Rate Base	**$4,181,449**	**$650,133**	**$135,691**	**$3,395,625**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 17D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD			-	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD			-	-	-
Steam Power - Maintenance	320-323	510-515	PROD			-	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD			-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD			-	-	-
Nuclear - Maintenance	320-323	528-532	PROD			-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD			-	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD			-	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD		657,647	657,647	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD		38,825	38,825	-	-
Other Power - Maintenance	320-323	551-554.1	PROD		82,251	82,251	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	326	555	PROD		48,160,321	48,160,321	-	-
System Control and Load Dispatching	320-323	556	PROD		594,227	594,227	-	-
Other Expenses	320-323	557	PROD		7,336,274	7,336,274	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (a) (h)			DIRECT					
Total Production Expense					**$ 56,869,545**	**$ 56,869,545**	**$ -**	**$ -**
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS			-	-	-
Total Operations less Wheeling	320-323	560-567.1	TRANS		18,011	-	18,011	-
Total Maintenance	320-323	568-574	TRANS		1,775	-	1,775	-
Total Transmission Expense					**$ 19,786**	**$ -**	**$ 19,786**	**$ -**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 17D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Distribution Expense:								
Total Operations	320-323	580-589	DIST		1,267,088	-	-	1,267,088
Total Maintenance	320-323	590-598	DIST		1,321,939	-	-	1,321,939
Total Distribution Expense					$ 2,589,027	$ -	$ -	$ 2,589,027
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST		1,577,147	-	-	1,577,147
Customer Service and Information	320-323	906-907	DIST		81,434	-	-	81,434
Customer Assistance Expenses (Major only)	320-323	908	DIRECT					
Customer Service and Information	320-323	909-910	DIST			-	-	-
Total Sales Expense	320-323	911-917	DIST			-	-	-
Total Customer and Sales Expenses					$ 1,658,581	$ -	$ -	$ 1,658,581
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR		1,131,840	111,150	12,819	1,007,871
Office Supplies & Expenses	320-323	921	LABOR		208,744	20,499	2,364	185,881
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR			-	-	-
Outside Services Employed (g)	320-323	923	LABOR		239,401	23,510	2,711	213,180
Property Insurance	320-323	924	PTDG		130,843	20,609	4,566	105,669
Injuries and Damages	320-323	925	LABOR		447	44	5	398
Employee Pensions & Benefits	320-323	926	LABOR		1,953,923	191,881	22,130	1,739,912
Franchise Requirements	320-323	927	DIST			-	-	-
Regulatory Commission Expenses	320-323	928	DIST			-	-	-
(Less) Duplicate Charges - Credit	320-323	929	PTDG			-	-	-
General Advertising Expenses (g)	320-323	930.1	DIST	DIST		-	-	-
Miscellaneous General Expenses	320-323	930.2	DIST		415,918	-	-	415,918
Rents	320-323	931	DIST			-	-	-
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM			-	-	-
Total Administration and General Expenses					$ 4,081,116	$ 367,693	$ 44,595	$ 3,668,828

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 17D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Total Operations and Maintenance					$ 65,218,055	$ 57,237,238	$ 64,381	$ 7,916,436
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST		-	-	-
Steam Production Plant	336	403	PROD			-	-	-
Nuclear Production Plant	336	403	PROD			-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD			-	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD			-	-	-
Other Production Plant	336	403	PROD		662,455	662,455	-	-
Transmission Plant (i)	336	403	TRANS		141,872	-	141,872	-
Distribution Plant	336	403	DIST		3,273,906	-	-	3,273,906
General Plant	336	403	GP		452,715	59,931	14,607	378,177
Common Plant - Electric	336	403	DIRECT					
Common Plant - Electric	336	404	DIRECT					
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT					
Amortization of Limited Term Electric Plant	336	404	DIRECT					
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIRECT					
Total Depreciation and Amortization					$ 4,530,948	$ 722,386	$ 156,479	$ 3,652,083
Total Operating Expenses					$ 69,749,003	$ 57,959,624	$ 220,860	$ 11,568,519
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 17E: Schedule 3A Items: Taxes

Account Description	FERC Form 1		Funct. Method	Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers					
FEDERAL							
Income Tax	262	409.1	DIST		-	-	-
Employment Tax	262	408.1	LABOR	351,768	34,545	3,984	313,239
Other Federal Taxes	262	408.1	DIST		-	-	-
TOTAL FEDERAL				**$ 351,768**	**$ 34,545**	**$ 3,984**	**$ 313,239**
STATE AND OTHER							
Property or In-Lieu (c)	262	408.1	PTDG		-	-	-
Unemployment	262	408.1	LABOR	67,685	6,647	767	60,272
State Income, B&O, etc.	262	409.1	DIST	2,485,339	-	-	2,485,339
Franchise Fees	262	408.1	DIST		-	-	-
Regulatory Commission	262	408.1	DIST		-	-	-
City/Municipal	262	408.1	DIST		-	-	-
Other	262	408.1	DIST	1,301,536	-	-	1,301,536
TOTAL STATE AND OTHER TAXES				**$ 3,854,560**	**$ 6,647**	**$ 767**	**$ 3,847,147**
TOTAL TAXES				**$ 4,206,328**	**$ 41,192**	**$ 4,751**	**$ 4,160,386**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 17F: Schedule 3B Other Included Items (j)

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD		-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST		-	-	-
Gain from Disposition of Utility Plant	114	411.6	DIRECT	PROD		-	-	-
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST		-	-	-
Gain from Disposition of Allowances	114	411.8	PROD			-	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD			-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD		-	-	-
Total Other Included Items					$ -	$ -	$ -	$ -
Sales for Resale:								
Sales for Resale	310	447	PROD		14,866,154	14,866,154	-	-
Total Sales for Resale					**$ 14,866,154**	**$ 14,866,154**	$ -	$ -
Other Revenues:								
Forfeited Discounts	300	450	DIST		174,704	-	-	174,704
Miscellaneous Service Revenues	300	451	DIST		4,246,779	-	-	4,246,779
Sales of Water and Water Power	300	453	PROD			-	-	-
Rent from Electric Property	300	454	TD		114,985	-	4,867	110,118
Interdepartmental Rents	300	455	DIST			-	-	-
Other Electric Revenues	300	456	DIRECT	PROD	2,685,267	-	-	2,685,267
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS		2,841	-	2,841	-
Total Other Revenues					**$ 7,224,576**	$ -	**$ 7,708**	**$ 7,216,868**
Total Other Included Items					**$ 22,090,730**	**$ 14,866,154**	**$ 7,708**	**$ 7,216,868**

(Total Other + Total Sales for Resale + Total Other Revenue)

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 17G: Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses *(From Schedule 3)*	$ 69,749,003	$ 57,959,624	$ 220,860	$ 11,568,519
Federal Income Tax Adjusted Return on Rate Base *(From Schedule 2)*	$ 4,181,449	$ 650,133	$ 135,691	$ 3,395,625
State and Other Taxes *(From Schedule 3a)*	$ 4,206,328	$ 41,192	$ 4,751	$ 4,160,386
Total Other Included Items *(From Schedule 3b)*	$ 22,090,730	$ 14,866,154	$ 7,708	$ 7,216,868
Total Cost	**$ 56,046,050**	**$ 43,784,794**	**$ 353,594**	**$ 11,907,662**

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 17G: Schedule 4: Average System Cost

Contract System Cost		
Production	$	43,784,794
Transmission	$	353,594
(Less) New Large Single Load Costs (d)		
Total Contract System Cost	**$**	**44,138,388**
Contract System Load (MWh)		
Total Retail Load		835,781
(Less) New Large Single Load		
Total Retail Load (Net of NLSL) (d)		835,781
Distribution Loss (e)		41,789
Total Contract System Load		**877,570**
Average System Cost $/MWh		**50.30**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 17H: Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	163,488
Transmission	354-355	
Distribution	354-355	723,908
Customer Accounts	354-355	724,810
Customer Service and Information	354-355	65,548
Sales	354-355	
Administrative and General	354-355	1,130,861
TOTAL Operation		**$2,808,615**
Maintenance		
Production	354-355	
Transmission	354-355	
Distribution	354-355	729,927
Administrative and General	354-355	
TOTAL Maintenance		**$729,927**
Operation and Maintenance		
Production (Total of lines 16 and 26)	354-355	163,488
Transmission (Total of lines 17 and 27)	354-355	0
Distribution (Total of lines 18 and 28)	354-355	1,453,835
Customer Accounts (From line 20)	354-355	724,810
Customer Service and Information (From line 20)	354-355	65,548
Sales (From line 21)	354-355	0
Administrative and General (Total of lines 22 and 29)	354-355	1,130,861
TOTAL Operation and Maintenance		**$3,538,542**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

***TABLE 17I*: Ratio Table**

Labor Ratio Input:

	Ratio Used	Total	Production	Transmission	Distribution
Production	PROD	$ 163,488	$ 163,488	$ -	$ -
Transmission	TRANS	-	-	-	-
Distribution	DIST	1,453,835	-	-	1,453,835
Customer Accounts	DIST	724,810	-	-	724,810
Customer Service and Informational	DIRECT	65,548	-	-	65,548
Sales	DIST	-	-	-	-
Administrative & General	PTD	1,130,861	184,007	40,077	906,777
Total Labor		$ 3,538,542	$ 347,495	$ 40,077	$ 3,150,970
LABOR RATIO		**100%**	**10%**	**1%**	**89%**

GP	General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Land and Land Rights	PTD	$ 128,960	$ 20,984	$ 4,570	$ 103,406
	Structures and Improvements	PTD	5,222,950	849,849	185,098	4,188,002
	Furniture and Equipment	LABOR	3,856,888	378,758	43,683	3,434,447
	Transportation Equipment	TD	2,793,281	-	118,230	2,675,051
	Stores Equipment	PTD	20,788	3,383	737	16,669
	Tools and Garage Equipment	PTD	730,593	118,878	25,892	585,823
	Laboratory Equipment	PTD	25,767	4,193	913	20,661
	Power Operated Equipment	TD	6,521	-	276	6,245
	Communication Equipment	PTD	8,934,819	1,453,824	316,645	7,164,350
	Miscellaneous Equipment	PTD	262,763	42,755	9,312	210,696
	Other Tangible Property	DIRECT	1,237,870	201,419	43,869	992,581
	Asset Retirement Costs for General Plant	PTD	-	-	-	-
	TOTAL		$ 23,221,200	$ 3,074,043	$ 749,225	$ 19,397,932
	GP RATIO		**100%**	**13%**	**3%**	**84%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

***TABLE 17I*: Ratio Table**

		Ratio Used	Total	Production	Transmission	Distribution
PTD	**Production, Transmission, Distribution Ratio**					
	Steam Production	PROD	$ -	$ -	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	-	-	-	-
	Other Production	PROD	18,232,751	18,232,751	-	-
	Total Production Plant		18,232,751	18,232,751	-	-
	Transmission Plant	TRANS	3,971,116	-	3,971,116	-
	Total Distribution Plant	DIST	89,849,816	-	-	89,849,816
	TOTAL		$ 112,053,683	$ 18,232,751	$ 3,971,116	$ 89,849,816
	PTD RATIO		**100%**	**16%**	**4%**	**80%**

		Ratio Used	Total	Production	Transmission	Distribution
PTDG	**Production, Transmission, Distribution and General Plant Ratio**					
	PTD Total		$ 112,053,683	$ 18,232,751	$ 3,971,116	$ 89,849,816
	Intangible Plant - Organization	DIST	-	-	-	-
	Intangible Plant - Franchises and Consents	DIRECT	-	-	-	-
	Intangible Plant - Miscellaneous	DIRECT	-	-	-	-
	General Plant Total		23,221,200	3,074,043	749,225	19,397,932
	TOTAL		$ 135,274,883	$ 21,306,794	$ 4,720,341	$ 109,247,748
	PTDG RATIO		**100%**	**16%**	**3%**	**81%**

		Ratio Used	Total	Production	Transmission	Distribution
TD	**Transmission and Distribution Plant Ratio**					
	Total Transmission Plant	TRANS	$ 3,971,116	$ -	$ 3,971,116	$ -
	Total Distribution Plant	DIST	89,849,816	-	-	89,849,816
	TOTAL		$ 93,820,932	$ -	$ 3,971,116	$ 89,849,816
	TD RATIO		**100%**	**0%**	**4%**	**96%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	PUD No. 1 of Franklin County
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 17I: Ratio Table

GPM	Maintenance of General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Structures and Improvements	PTD	$ 5,222,950	$ 849,849	$ 185,098	$ 4,188,002
	Furniture and Equipment	LABOR	3,856,888	378,758	43,683	3,434,447
	Communication Equipment	PTD	8,934,819	1,453,824	316,645	7,164,350
	Miscellaneous Equipment	PTD	262,763	42,755	9,312	210,696
	TOTAL		$ 18,277,420	$ 2,725,187	$ 554,738	$ 14,997,496
	GPM RATIO		100%	15%	3%	82%

SUMMARY RATIO TABLE

Direct to Distribution	**DIST**	**0.00%**	**0.00%**	**100.00%**
Direct to Production	**PROD**	**100.00%**	**0.00%**	**0.00%**
Direct to Transmission	**TRANS**	**0.00%**	**100.00%**	**0.00%**
Direct Allocation	**DIRECT**	**0.00%**	**0.00%**	**0.00%**
General Plant	**GP**	**13.24%**	**3.23%**	**83.54%**
Maintenance of General Plant	**GPM**	**14.91%**	**3.04%**	**82.05%**
Labor Ratios	**LABOR**	**9.82%**	**1.13%**	**89.05%**
Production, Transmission, Distribution	**PTD**	**16.27%**	**3.54%**	**80.18%**
Production, Transmission, Distribution, General	**PTDG**	**15.75%**	**3.49%**	**80.76%**
Transmission, Distribution	**TD**	**0.00%**	**4.23%**	**95.77%**

BONNEVILLE POWER ADMINSTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

TABLE 17J

UTILITY NAME:	PUD No. 1 of Franklin County
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

FERC Form 1		Purchased Power - Base Period		urchased Power - Base Period Minus		urchased Power - Base Period Minus	
Statistical Classification	Page Number	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
RQ	326-327						
LF	326-327	$ 43,164,106	1,019,243				
IF	326-327						
SF	326-327	$ 4,996,215	104,264				
LU	326-327						
IU	326-327						
OS	326-327						
EX	326-327						
NA	326-327						
AD	326-327						
TOTAL		$ 48,160,321	1,123,507	$ -	-	$ -	-

FERC Form 1		Sales for Resale - Base Period		ales for Resale - Base Period Minus		ales for Resale - Base Period Minus	
Statistical Classification	Page Number	Settlement Total	MWh Sold	Settlement Total	MWh Sold	Settlement Total	MWh Sold
RQ	310-311						
LF	310-311						
IF	310-311						
SF	310-311	$ 14,866,154	289,820				
LU	310-311						
IU	310-311						
OS	310-311						
EX	310-311						
NA	310-311						
AD	310-311						
TOTAL		$ 14,866,154	289,820	$ -	-	$ -	-

FRANKLIN **TABLE 17K: Forecasted Contract System Costs & ASC with New Additions and NLSL**

Date	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
	6	7	8	9	10
Fiscal Year	2009	2010	2011	2012	2013
Rate Period Mid-Point	**TRUE**	**FALSE**	**FALSE**	**FALSE**	**FALSE**
Contract System Cost					
Production	46,464,644	49,467,433	49,965,516	53,756,643	54,298,688
Transmission	339,921	334,953	330,161	325,252	320,254
NLSL Fully Allocated Cost ($/MWh)					
(Less) New Large Single Load Costs (d)	**0**	**0**	**0**	**0**	**0**
Total Contract System Cost	46,804,565	49,802,386	50,295,677	54,081,895	54,618,941
Contract System Load (MWh)					
Total Retail Load @ Meter	974,500	996,750	1,014,000	1,030,000	1,048,250
(Less) New Large Single Load	**0**	**0**	**0**	**0**	**0**
Total Retail Load (Net of NLSL) (d)	974,500	996,750	1,014,000	1,030,000	1,048,250
Distribution Loss (f)	48,725	49,838	50,700	51,500	52,413
Total Contract System Load	1,023,225	1,046,588	1,064,700	1,081,500	1,100,663
Average System Cost $/MWh	**45.74**	**47.59**	**47.24**	**50.01**	**49.62**

Rate Period Mid-Point

Date	**4/1/09**
Fiscal Year	2009
NLSL Switch	1
Contract System Cost	
Production	46,464,644
Transmission	339,921
(Less) New Large Single Load Costs (d)	0
Total Contract System Cost	46,804,565
Contract System Load (MWh)	
Total Retail Load @ Meter	974,500
(Less) New Large Single Load	**0**
Total Retail Load (Net of NLSL) (d)	974,500
Distribution Loss (f)	48,725
Total Contract System Load	1,023,225
Average System Cost $/MWh	**45.74**

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Tables for:

Idaho Power

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Idaho Power Company	
End of Year Report Period:	2006	
ASC Filing Date:	5/7/2008	Revised 6/18/2008 REB BPA
		Amended Revised 8/4/08

TABLE 18A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST		62,160	-	-	62,160
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD	21,711,627	15,167,410	6,544,217	-
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST	50,320,243	24,584,401	9,165,028	16,570,814
Total Intangible Plant					**$ 72,094,030**	**$ 39,751,811**	**$ 15,709,245**	**$ 16,632,974**
Production Plant:								
Steam Production	204-207	310-317	PROD		838,233,513	838,233,513	-	-
Nuclear Production	204-207	320-326	PROD			-	-	-
Hydraulic Production	204-207	330-337	PROD		647,622,099	647,622,099	-	-
Other Production	204-207	340-347	PROD		106,934,506	106,934,506	-	-
Total Production Plant					**$ 1,592,790,118**	**$ 1,592,790,118**	**$ -**	**$ -**
Transmission Plant: (i)								
Transmission Plant	204-207	350-359.1	TRANS		606,947,191	-	606,947,191	-
Total Transmission Plant					**$ 606,947,191**	**$ -**	**$ 606,947,191**	**$ -**
Distribution Plant:								
Distribution Plant	204-207	360-374	DIST		1,097,389,958	-	-	1,097,389,958
Total Distribution Plant					**$ 1,097,389,958**	**$ -**	**$ -**	**$ 1,097,389,958**
General Plant:								
Land and Land Rights	204-207	389	PTD		8,760,765	4,232,187	1,612,714	2,915,864
Structures and Improvements	204-207	390	PTD		64,391,078	31,106,313	11,853,344	21,431,421
Furniture and Equipment	204-207	391	LABOR		37,350,131	13,196,540	5,964,399	18,189,192
Transportation Equipment	204-207	392	TD		51,050,749	-	18,180,152	32,870,597
Stores Equipment	204-207	393	PTD		982,361	474,563	180,837	326,961
Tools and Garage Equipment	204-207	394	PTD		4,222,287	2,039,720	777,254	1,405,313
Laboratory Equipment	204-207	395	PTD		9,761,135	4,715,450	1,796,865	3,248,820
Power Operated Equipment	204-207	396	TD		7,306,985	-	2,602,158	4,704,827
Communication Equipment	204-207	397	PTD		28,196,828	13,621,442	5,190,575	9,384,811
Miscellaneous Equipment	204-207	398	PTD		2,904,743	1,403,235	534,716	966,792
Other Tangible Property	204-207	399	DIRECT	PTD		-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD			-	-	-
Total General Plant					**$ 214,927,062**	**$ 70,789,451**	**$ 48,693,013**	**$ 95,444,598**
Total Electric Plant In-Service					**$ 3,584,148,359**	**$ 1,703,331,380**	**$ 671,349,449**	**$ 1,209,467,530**

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Idaho Power Company
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Revised 6/18/2008 REB BPA

Amended Revised 8/4/08

TABLE 18A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD		420,177,111	420,177,111	-	-
Nuclear Production Plant	219	108	PROD			-	-	-
Hydraulic Production Plant	219	108	PROD		240,328,423	240,328,423	-	-
Other Production Plant	219	108	PROD		2,366,353	2,366,353	-	-
Transmission Plant (i)	219	108	TRANS		210,074,912	-	210,074,912	-
Distribution Plant	219	108	DIST		411,582,068	-	-	411,582,068
General Plant	219	108	GP		83,279,714	27,429,423	18,867,518	36,982,773
Amortization of Intangible Plant - Account 301	219	111	DIST			-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST		-	-	-
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	111	DIST			-	-	-
Capital Lease - Common Plant	219	108	Direct			-	-	-
Leasehold Improvements	200-201	108	DIRECT	DIST		-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT			-	-	-
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST	38,728,952	19,608,072	7,118,556	12,002,324
Amortization of Acquisition Adjustments	200-201	115	DIST		(327,581)	-	-	(327,581)
Depreciation and Amortization Reserve (Other)			DIRECT					
Total Depreciation and Amortization Reserve					$ 1,406,209,952	$ 709,909,382	$ 236,060,986	$ 460,239,584
Total Net Plant					$ 2,177,938,407	$ 993,421,999	$ 435,288,463	$ 749,227,945

(Total Electric Plant In-Service) - (Total Depreciation & Amortization)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME: **Idaho Power Company**
End of Year Report Period: **2006**
ASC Filing Date: **5/7/2008** Revised 6/18/2008 REB BPA
Amended Revised 8/4/08

TABLE 18A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation: Automatic Input from Sch 1A				29,123,883	10,361,798	4,649,072	14,113,013
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST		2,809,770	-	-	2,809,770
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD			-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST		210,094,019	-	-	210,094,019
Common Plant	356 & 356.1		DIRECT					
Acquisition Adjustments (Electric)	200-201	114	DIST	DIST	(454,449)	-	-	(454,449)
Total					**$ 212,449,340**	**$ -**	**$ -**	**$ 212,449,340**
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST		-	-	-
Other Investment	110-111	124	DIST		3,696	-	-	3,696
Long-Term Portion of Derivative Assets	110-111	175	DIST			-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST			-	-	-
Total					**$ 3,696**	**$ -**	**$ -**	**$ 3,696**
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD		15,173,831	15,173,831	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD			-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD		36,762,206	17,759,241	6,767,321	12,235,644
Merchandise (Major Only)	110-112	155	DIST			-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST			-	-	-
EPA Allowance Inventory	110-112	158.1	PROD			-	-	-
EPA Allowances Withheld	110-112	158.2	PROD			-	-	-
Stores Expense Undistributed	110-111	163	PTD		2,316,011	1,118,828	426,340	770,843
Prepayments	110-111	165	PTD		8,952,014	4,324,577	1,647,919	2,979,518
Derivative Instrument Assets	110-111	175	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST			-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST			-	-	-
Total					**$ 63,204,062**	**$ 38,376,477**	**$ 8,841,580**	**$ 15,986,005**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME: **Idaho Power Company**
End of Year Report Period: **2006**
ASC Filing Date: **5/7/2008** **Revised 6/18/2008 REB BPA**
Amended Revised 8/4/08

TABLE 18A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG		9,786,336	4,650,860	1,833,086	3,302,390
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST		-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST		-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST	378,846,883	188,089,121	68,763,303	121,994,459
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST		416,116	-	-	416,116
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST			-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST			-	-	-
Clearing Accounts	110-111	184	DIST		361,477	-	-	361,477
Temporary Facilities	110-111	185	PTDG			-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST	124,388,934	74,821,604	22,671,331	26,895,999
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT					
Research, Development, and Demonstration Expenditures	110-111	188	DIST			-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG		14,760,653	7,014,856	2,764,829	4,980,969
Accumulated Deferred Income Taxes	110-111	190	DIST		117,138,886	-	-	117,138,886
Total					**$ 645,699,285**	**$ 274,576,441**	**$ 96,032,548**	**$ 275,090,296**
Total Assets and Other Debits					**$ 950,480,266**	**$ 323,314,716**	**$ 109,523,200**	**$ 517,642,350**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Idaho Power Company
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Revised 6/18/2008 REB BPA

Amended Revised 8/4/08

TABLE 18A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Liabilities and Other Credits (Comparative Balance Sheet)								
CURRENT AND ACCRUED LIABILITIES								
Derivative Instrument Liabilities	112-113	244	DIST		1,462,637	-	-	1,462,637
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST			-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST			-	-	-
Total					**$ 1,462,637**	**$ -**	**$ -**	**$ 1,462,637**
DEFERRED CREDITS								
Customer Advances for Construction	112-113	252	DIST		26,085,511	-	-	26,085,511
Other Deferred Credits	112-113	253	DIRECT	DIST	25,567,500	7,401,103	13,330,354	4,836,043
Other Regulatory Liabilities	112-113	254	DIRECT	DIST	225,731,042	124,119,234	35,429,436	66,182,372
Accumulated Deferred Investment Tax Credits	112-113	255	DIST		69,113,142	-	-	69,113,142
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT					
Unamortized Gain on Reacquired Debt	112-113	257	PTDG			-	-	-
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST			-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST		573,951,058	-	-	573,951,058
Accumulated Deferred Income Taxes-Other	112-113	283	DIST		32,746,932	-	-	32,746,932
Total					**$ 953,195,185**	**$ 131,520,337**	**$ 48,759,790**	**$ 772,915,058**
Total Liabilities and Other Credits					**$ 954,657,822**	**$ 131,520,337**	**$ 48,759,790**	**$ 774,377,695**
Total Rate Base					**$ 2,173,760,851**	**$ 1,185,216,378**	**$ 496,051,873**	**$ 492,492,600**

Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Revised 6/18/2008 REB BPA
Amended Revised 8/4/08

TABLE 18B: Schedule 1A: Cash Working Capital (f)

(Automatic Input from Schedule 3- Expenses)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	450,096,498	450,096,498	-	-
Total Transmission O&M (i)	23,669,858	-	23,669,858	-
Total Distribution O&M	41,984,481	-	-	41,984,481
Total Customer & Sales	28,971,362	940,836	-	28,030,526
Total Administrative and General O&M	86,726,893	30,315,081	13,522,714	42,889,097
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	398,458,031	398,458,031	-	-
Revised Total O&M Expenses	**$ 232,991,061**	**$ 82,894,384**	**$ 37,192,572**	**$ 112,904,104**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 29,123,883**	**$ 10,361,798**	**$ 4,649,072**	**$ 14,113,013**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company	
End of Year Report Period:	12/31/2006	Revised 6/18/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 18C: Schedule 2: Capital Structure and Rate of Return (b)

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:		
Multi-Jurisdiction Investor-Owned Utility Return Calculation:	11%	0.10944
Consumer-Owned Utility Return Calculation:		
Rate of Return :	10.9446%	

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order

Note: Multi-jurisdictional utilities must begin on Page 2

Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**
Debt				
Preferred Equity				
Common Equity				
Weighted Cost of Capital	$ -			

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	35%	
Federal Income Tax Factor		

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 2,173,760,851	$ 1,185,216,378	$ 496,051,873	$ 492,492,600
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company	
End of Year Report Period:	12/31/2006	Revised 6/18/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 18C: Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation

Step 1:

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 1

	Capitalization Structure		Effective Cost		Jurisdictional	Effective Cost -	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**	**Allocation**	**Weighted**	**State Allocation**
Debt	$ 1,108,460,000	49.7%	5.59%	2.781%	95.00%	2.64%	47.250%
Preferred Equity							
Common Equity	$ 1,120,188,586	50.3%	10.60%	5.328%		5.06%	47.75%
Weighted Cost of Capital	**$ 2,228,648,586**	**100.00%**		**8.109%**		7.70%	95.00%

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 2

Component	**Amount**	**Percent**	**Embedded**	**Weighted**			
Debt		54.0%	5.99%	3.235%	5.00%	0.16%	2.700%
Preferred Equity							
Common Equity		46.0%	10.00%	4.600%		0.23%	2.30%
Weighted Cost of Capital	**$ -**	**100.00%**		**7.835%**		0.39%	5.00%

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 3

Component	**Amount**	**Percent**	**Embedded**	**Weighted**			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	**$ -**						

Jurisdiction	**Rate Base**	**Weighted cost**	**%**	**Weighted Return**		
Idaho		8.11%	7.70%			7.70%
Oregon		7.84%	0.39%			0.39%
Total			**8.10%**		**100.00%**	**8.095%**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	**Idaho Power Company**	
End of Year Report Period:	**12/31/2006**	**Revised 6/18/2008 REB BPA**
ASC Filing Date:	**5/7/2008**	**Amended Revised 8/4/08**

TABLE 18C: Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation *(continued)*

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	**35%**	
Federal Income Tax Factor		**2.849%**
*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*		
Federal Income Tax Adjusted Weighted Cost of Capital		**10.9446%**
(Weighted Cost of Capital Plus Federal Income Tax Factor)		

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 2,173,760,851	$ 1,185,216,378	$ 496,051,873	$ 492,492,600
Federal Income Tax Adjusted Weighted Cost of Capital	10.945%	10.945%	10.945%	10.945%
Federal Income Tax Adjusted Return on Rate Base	**$237,909,932**	**$129,717,465**	**$54,291,008**	**$53,901,459**
*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*				

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company
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Revised 6/18/2008 REB BPA

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TABLE 18C: Schedule 2: Capital Structure and Rate of Return (b)

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

Debt Issue	Original Amount	Year Issued	Year Due	Interest Rate	Interest Expense
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	$ -				$ -

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 2,173,760,851	$ 1,185,216,378	$ 496,051,873	$ 492,492,600
Weighted Cost of Debt				
Return on Rate Base				

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME: **Idaho Power Company**
End of Year Report Period: **12/31/2006** Revised 6/18/2008 REB BPA
ASC Filing Date: **5/7/2008** Amended Revised 8/4/08TABLE

TABLE 18D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD		107,519,847	107,519,847	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD		18,655,548	18,655,548	-	-
Steam Power - Maintenance	320-323	510-515	PROD		27,321,286	27,321,286	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD			-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD			-	-	-
Nuclear - Maintenance	320-323	528-532	PROD			-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD		21,922,426	21,922,426	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD		9,363,762	9,363,762	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD		7,498,309	7,498,309	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD		909,911	909,911	-	-
Other Power - Maintenance	320-323	551-554.1	PROD		693,980	693,980	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	320-323	555	PROD		283,439,875	283,439,875	-	-
System Control and Load Dispatching	320-323	556	PROD		76,140	76,140	-	-
Other Expenses	320-323	557	PROD		(27,304,586)	(27,304,586)	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (h)			DIRECT					
Total Production Expense					**$ 450,096,498**	**$ 450,096,498**	**$ -**	**$ -**
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS		7,638,680	-	7,638,680	-
Total Operations less Wheeling	320-323	560-567.1	TRANS		10,182,975	-	10,182,975	-
Total Maintenance	320-323	568-574	TRANS		5,848,203	-	5,848,203	-
Total Transmission Expense					**$ 23,669,858**	**$ -**	**$ 23,669,858**	**$ -**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company	
End of Year Report Period:	12/31/2006	Revised 6/18/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 18D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Distribution Expense:								
Total Operations	320-323	580-589	DIST		24,461,390	-	-	24,461,390
Total Maintenance	320-323	590-598	DIST		17,523,091	-	-	17,523,091
Total Distribution Expense					$ 41,984,481	$ -	$ -	$ 41,984,481
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST		18,787,288	-	-	18,787,288
Customer Service and Information	320-323	906-907	DIST		288,822	-	-	288,822
Customer Assistance Expenses (Major only)	320-323	908	DIRECT		9,047,316	940,836	-	8,106,480
Customer Service and Information	320-323	909-910	DIST		847,936	-	-	847,936
Total Sales Expense	320-323	911-917	DIST			-	-	-
Total Customer and Sales Expenses					$ 28,971,362	$ 940,836	$ -	$ 28,030,526
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR		48,935,653	17,289,934	7,814,478	23,831,241
Office Supplies & Expenses	320-323	921	LABOR		14,665,999	5,181,788	2,341,996	7,142,215
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR		29,324,259	10,360,841	4,682,757	14,280,661
Outside Services Employed	320-323	923	LABOR		8,149,646	2,879,431	1,301,408	3,968,807
Property Insurance	320-323	924	PTDG		2,945,897	1,400,009	551,798	994,090
Injuries and Damages	320-323	925	LABOR		5,152,000	1,820,303	822,717	2,508,980
Employee Pensions & Benefits	320-323	926	LABOR		29,241,894	10,331,740	4,669,604	14,240,550
Franchise Requirements	320-323	927	DIST		2,000	-	-	2,000
Regulatory Commission Expenses	320-323	928	DIST		976,225	-	-	976,225
(Less) Duplicate Charges - Credit	320-323	929	PTDG			-	-	-
General Advertising Expenses	320-323	930.1	DIST	DIST	107,310	-	-	107,310
Miscellaneous General Expenses	320-323	930.2	DIST		1,901,158	-	-	1,901,158
Rents	320-323	931	DIST		4,003	-	-	4,003
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM		3,969,367	1,772,718	703,470	1,493,179
Total Administration and General Expenses					$ 86,726,893	$ 30,315,081	$ 13,522,714	$ 42,889,097

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company	
End of Year Report Period:	12/31/2006	Revised 6/18/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 18D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Total Operations and Maintenance					$ 631,449,092	$ 481,352,415	$ 37,192,572	$ 112,904,104
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD	700,690	400,503	300,187	-
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST	8,388,971	4,058,913	1,542,017	2,788,041
Steam Production Plant	336	403	PROD		23,623,910	23,623,910	-	-
Nuclear Production Plant	336	403	PROD			-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD		12,606,566	12,606,566	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD			-	-	-
Other Production Plant	336	403	PROD		3,035,377	3,035,377	-	-
Transmission Plant (i)	336	403	TRANS		12,905,223	-	12,905,223	-
Distribution Plant	336	403	DIST		27,682,064	-	-	27,682,064
General Plant	336	403	GP		11,246,569	3,704,226	2,547,978	4,994,365
Common Plant - Electric	336	403	DIRECT		(296,299)			(296,299)
Common Plant - Electric	336	404	DIRECT					
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT					
Amortization of Limited Term Electric Plant	336	404	DIRECT					
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIST		(327,581)			(327,581)
Total Depreciation and Amortization					$ 99,565,490	$ 47,429,495	$ 17,295,405	$ 34,840,590
Total Operating Expenses					$ 731,014,582	$ 528,781,911	$ 54,487,977	$ 147,744,694
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company	
End of Year Report Period:	12/31/2006	Revised 6/18/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 18E: Schedule 3A Items: Taxes (Including Income Taxes)

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Funct. Method	Total	Production	Transmission	Distribution/ Other
FEDERAL							
Income Tax (Included on Schedule 2)	262	409.1	DIST	74,035,895	-	-	74,035,895
Employment Tax	262	408.1	LABOR	114,279	40,377	18,249	55,653
Other Federal Taxes	262	408.1	DIST	9,868,447	-	-	9,868,447
TOTAL FEDERAL				**$ 84,018,621**	**$ 40,377**	**$ 18,249**	**$ 83,959,995**
STATE AND OTHER							
Property	262	408.1	PTDG	15,684,255	7,453,788	2,937,829	5,292,637
Unemployment	262	408.1	LABOR	283,157	100,045	45,217	137,895
State Income, B&O, et.	262	409.1	DIST	9,099,952	-	-	9,099,952
Franchise Fees	262	408.1	DIST	500,221	-	-	500,221
Regulatory Commission	262	408.1	DIST	1,784,719	-	-	1,784,719
City/Municipal	262	408.1	DIST	0	-	-	-
Other	262	408.1	DIST	2,064,967	-	-	2,064,967
TOTAL STATE AND OTHER TAXES				**$ 29,417,271**	**$ 7,553,833**	**$ 2,983,046**	**$ 18,880,391**
TOTAL TAXES				**$ 113,435,892**	**$ 7,594,210**	**$ 3,001,295**	**$ 102,840,386**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company	
End of Year Report Period:	12/31/2006	Revised 6/18/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 18F: Schedule 3B Other Included Items

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD		-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST	10,391,371	5,136,609	1,871,322	3,383,440
Gain from Disposition of Utility Plant	114	411.6	PROD	PROD	46,144	46,144	-	-
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST		-	-	-
Gain from Disposition of Allowances	114	411.8	PROD		8,257,817	8,257,817	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD			-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD	5,189,612	3,044,891	763,777	1,380,944
Total Other Included Items					**$ 3,102,202**	**$ 6,212,243**	**$ (1,107,545)**	**$ (2,002,496)**
Sales for Resale:								
Sales for Resale	310	447	PROD		260,717,491	260,717,491	-	-
Total Sales for Resale					**$ 260,717,491**	**$ 260,717,491**	**$ -**	**$ -**
Other Revenues:								
Forfeited Discounts	300	450	DIST			-	-	-
Miscellaneous Service Revenues	300	451	DIST		5,424,893	-	-	5,424,893
Sales of Water and Water Power	300	453	PROD			-	-	-
Rent from Electric Property	300	454	TD		16,858,178	-	6,003,521	10,854,657
Interdepartmental Rents	300	455	DIST			-	-	-
Other Electric Revenues	300	456	DIRECT	PROD	297,623	61,919	85,052	150,652
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS		12,156,837	-	12,156,837	-
Total Other Revenues					**$ 34,737,531**	**$ 61,919**	**$ 18,245,410**	**$ 16,430,202**
Total Other Included Items					**$ 298,557,224**	**$ 266,991,653**	**$ 17,137,865**	**$ 14,427,706**

(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Revised 6/18/2008 REB BPA

Amended Revised 8/4/08

TABLE 18G: Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses *(From Schedule 3)*	$ 731,014,582	$ 528,781,911	$ 54,487,977	$ 147,744,694
Federal Income Tax Adjusted Return on Rate Base *(From Schedule 2)*	$ 237,909,932	$ 129,717,465	$ 54,291,008	$ 53,901,459
State and Other Taxes *(From Schedule 3a)*	$ 113,435,892	$ 7,594,210	$ 3,001,295	$ 102,840,386
Total Other Included Items *(From Schedule 3b)*	$ 298,557,224	$ 266,991,653	$ 17,137,865	$ 14,427,706
Total Cost	**$ 783,803,182**	**$ 399,101,933**	**$ 94,642,415**	**$ 290,058,833**

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Revised 6/18/2008 REB BPA

Amended Revised 8/4/08

TABLE 18G: Schedule 4: Average System Cost

Contract System Cost	
Production	$ 399,101,933
Transmission	$ 94,642,415
(Less) New Large Single Load Costs (d)	$ 26,461,649
Total Contract System Cost	**$ 467,282,700**
Contract System Load (MWh)	
Total Retail Load	13,939,314
(Less) New Large Single Load	385,440
Total Retail Load (Net of NLSL) (d)	13,553,874
Distribution Loss (f)	1,084,713
Total Contract System Load	**14,638,587**
Average System Cost $/MWh	**31.92**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Revised 6/18/2008 REB BPA
Amended Revised 8/4/08

TABLE 18H: Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	11,500,630
Transmission	354-355	6,979,846
Distribution	354-355	15,973,997
Customer Accounts	354-355	10,164,049
Customer Service and Information	354-355	4,187,137
Sales	354-355	0
Administrative and General	354-355	33,176,001
TOTAL Operation		**$81,981,660**
Maintenance		
Production	354-355	6,405,324
Transmission	354-355	2,454,601
Distribution	354-355	6,617,820
Administrative and General	354-355	884,361
TOTAL Maintenance		**$16,362,106**
Operation and Maintenance		
Production (Enter Total of lines 1 and 9)	354-355	17,905,954
Transmission (Enter Total of lines 2 and 10)	354-355	9,434,447
Distribution (Enter Total of lines 3 and 11)	354-355	22,591,817
Customer Accounts (Transcribe from line 4)	354-355	10,164,049
Customer Service and Information (Transcribe from line 5)	354-355	4,187,137
Sales (Transcribe from line 6)	354-355	0
Administrative and General (Enter Total of lines 7 and 12)	354-355	34,060,362
TOTAL Operation and Maintenance		**$98,343,766**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company	
End of Year Report Period:	12/31/2006	Revised 6/18/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 18I: Ratio Table

Labor Ratio Input:

	Ratio Used	Total	Production	Transmission	Distribution
Production	PROD	$ 17,905,954	$ 17,905,954	$ -	$ -
Transmission	TRANS	9,434,447	-	9,434,447	-
Distribution	DIST	22,591,817	-	-	22,591,817
Customer Accounts	DIST	10,164,049	-	-	10,164,049
Customer Service and Informational	DIRECT	4,187,137	386,821	-	3,800,316
Sales	DIST	-	-	-	-
Administrative & General	PTD	34,060,362	16,454,023	6,269,955	11,336,384
Total Labor		$ 98,343,766	$ 34,746,798	$ 15,704,402	$ 47,892,566
LABOR RATIO		**100%**	**35%**	**16%**	**49%**

GP

General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
Land and Land Rights	PTD	$ 8,760,765	$ 4,232,187	$ 1,612,714	$ 2,915,864
Structures and Improvements	PTD	64,391,078	31,106,313	11,853,344	21,431,421
Furniture and Equipment	LABOR	37,350,131	13,196,540	5,964,399	18,189,192
Transportation Equipment	TD	51,050,749	-	18,180,152	32,870,597
Stores Equipment	PTD	982,361	474,563	180,837	326,961
Tools and Garage Equipment	PTD	4,222,287	2,039,720	777,254	1,405,313
Laboratory Equipment	PTD	9,761,135	4,715,450	1,796,865	3,248,820
Power Operated Equipment	TD	7,306,985	-	2,602,158	4,704,827
Communication Equipment	PTD	28,196,828	13,621,442	5,190,575	9,384,811
Miscellaneous Equipment	PTD	2,904,743	1,403,235	534,716	966,792
Other Tangible Property	DIRECT	-	-	-	-
Asset Retirement Costs for General Plant	PTD	-	-	-	-
TOTAL		$ 214,927,062	$ 70,789,451	$ 48,693,013	$ 95,444,598
GP RATIO		**100%**	**33%**	**23%**	**44%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company	
End of Year Report Period:	12/31/2006	Revised 6/18/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 18I: Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
PTD	**Production, Transmission, Distribution Ratio**	**Ratio Used**	**Total**	**Production**	**Transmission**	**Distribution**
	Steam Production	PROD	$ 838,233,513	$ 838,233,513	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	647,622,099	647,622,099	-	-
	Other Production	PROD	106,934,506	106,934,506	-	-
	Total Production Plant		1,592,790,118	1,592,790,118	-	-
	Transmission Plant	TRANS	606,947,191	-	606,947,191	-
	Total Distribution Plant	DIST	1,097,389,958	-	-	1,097,389,958
	TOTAL		$ 3,297,127,267	$ 1,592,790,118	$ 606,947,191	$ 1,097,389,958
	PTD RATIO		**100%**	**48%**	**18%**	**33%**

		Ratio Used	Total	Production	Transmission	Distribution
PTDG	**Production, Transmission, Distribution and General Plant Ratio**	**Ratio Used**	**Total**	**Production**	**Transmission**	**Distribution**
	PTD Total		$ 3,297,127,267	$ 1,592,790,118	$ 606,947,191	$ 1,097,389,958
	Intangible Plant - Organization	DIST	62,160	-	-	62,160
	Intangible Plant - Franchises and Consents	DIRECT	21,711,627	15,167,410	6,544,217	-
	Intangible Plant - Miscellaneous	DIRECT	50,320,243	24,584,401	9,165,028	16,570,814
	General Plant Total		214,927,062	70,789,451	48,693,013	95,444,598
	TOTAL		$ 3,584,148,359	$ 1,703,331,380	$ 671,349,449	$ 1,209,467,530
	PTDG RATIO		**100%**	**48%**	**19%**	**34%**

		Ratio Used	Total	Production	Transmission	Distribution
TD	**Transmission and Distribution Plant Ratio**	**Ratio Used**	**Total**	**Production**	**Transmission**	**Distribution**
	Total Transmission Plant	TRANS	$ 606,947,191	$ -	$ 606,947,191	$ -
	Total Distribution Plant	DIST	1,097,389,958	-	-	1,097,389,958
	TOTAL		$ 1,704,337,149	$ -	$ 606,947,191	$ 1,097,389,958
	TD RATIO		**100%**	**0%**	**36%**	**64%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho Power Company	
End of Year Report Period:	12/31/2006	Revised 6/18/2008 REB BPA
ASC Filing Date:	5/7/2008	Amended Revised 8/4/08

TABLE 18I: Ratio Table

GPM	Maintenance of General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Structures and Improvements	PTD	$ 64,391,078	$ 31,106,313	$ 11,853,344	$ 21,431,421
	Furniture and Equipment	LABOR	37,350,131	13,196,540	5,964,399	18,189,192
	Communication Equipment	PTD	28,196,828	13,621,442	5,190,575	9,384,811
	Miscellaneous Equipment	PTD	2,904,743	1,403,235	534,716	966,792
	TOTAL		$ 132,842,780	$ 59,327,531	$ 23,543,034	$ 49,972,215
	GPM RATIO		100%	45%	18%	38%

SUMMARY RATIO TABLE

Direct to Distribution	DIST	0.00%	0.00%	100.00%
Direct to Production	PROD	100.00%	0.00%	0.00%
Direct to Transmission	TRANS	0.00%	100.00%	0.00%
Direct Allocation	DIRECT	0.00%	0.00%	0.00%
General Plant	GP	32.94%	22.66%	44.41%
Maintenance of General Plant	GPM	44.66%	17.72%	37.62%
Labor Ratios	LABOR	35.33%	15.97%	48.70%
Production, Transmission, Distribution	PTD	48.31%	18.41%	33.28%
Production, Transmission, Distribution, General	PTDG	47.52%	18.73%	33.74%
Transmission, Distribution	TD	0.00%	35.61%	64.39%

BONNEVILLE POWER ADMINSTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

TABLE 18J

UTILITY NAME:	Idaho Power Company
End of Year Report Period:	12/31/2006
ASC Filing Date:	5/7/2008

Revised 6/18/2008 REB BPA
Amended Revised 8/4/08

FERC Form 1 Statistical Classification	Page Number	Purchased Power - Base Period Settlement Total	Purchased Power - Base Period MWh Purchased	Purchased Power - Base Period Minus 1 Settlement Total	Purchased Power - Base Period Minus 1 MWh Purchased	Purchased Power - Base Period Minus 2 Settlement Total	Purchased Power - Base Period Minus 2 MWh Purchased
RQ	326-327						
LF	326-327	$ 4,609,488	103,584	$ 7,582,933	157,636	$ 3,554,304	79,872
IF	326-327	$ 4,034,733	95,612			$ 1,930,867	48,457
SF	326-327	$ 199,898,757	3,431,736	$ 148,730,964	2,679,186	$129,584,651	2,973,972
LU	326-327	$ 49,602,601	839,859	$ 42,312,915	691,083	$ 39,633,969	671,910
IU	326-327						
OS	326-327	$ 25,293,796	493,233	$ 23,592,338	390,484	$ 20,826,678	485,665
EX	326-327						
NA	326-327			$ 92,515	0	$ 111,724	0
AD	326-327			$ (1,350)	0		0
TOTAL		**$ 283,439,375**	**4,964,024**	**$ 222,310,315**	**3,918,389**	**$ 195,642,193**	**4,259,876**

FERC Form 1 Statistical Classification	Page Number	Sales for Resale - Base Period Settlement Total	Sales for Resale - Base Period MWh Sold	Sales for Resale - Base Period Minus 1 Settlement Total	Sales for Resale - Base Period Minus 1 MWh Sold	Sales for Resale - Base Period Minus 2 Settlement Total	Sales for Resale - Base Period Minus 2 MWh Sold
RQ	310-311	$ 3,485,271	108,970	$ 3,424,472	107,606	$ 3,300,005	104,331
LF	310-311			$ 293,363	10,256	$ 570,036	19,354
IF	310-311	$ 6,054,059	57,848	$ 7,069,470	58,617	$ 5,280,645	44,231
SF	310-311	$ 226,307,951	5,153,485	$ 119,130,850	2,308,517	$ 102,487,874	2,468,846
LU	310-311						
IU	310-311						
OS	310-311	$ 24,870,210	500,520	$ 12,875,621	288,856	$ 9,509,086	248,588
EX	310-311						
NA	310-311						
AD	310-311						
TOTAL		**$ 260,717,491**	**5,820,823**	**$ 142,793,776**	**2,773,852**	**$ 121,147,646**	**2,885,350**

IDAHO

TABLE 18K: Forecasted Contract System Costs & ASC with New Additions and NLSL

Date	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
	6	7	8	9	10
Fiscal Year	2009	2010	2011	2012	2013
Rate Period Mid-Point	**TRUE**	**FALSE**	**FALSE**	**FALSE**	**FALSE**
Contract System Cost					
Production	470,949,913	481,694,355	496,739,225	505,581,825	518,655,158
Transmission	93,579,418	92,933,257	92,316,991	91,643,186	91,009,961
NLSL Fully Allocated Cost ($/MWh)	79.11	76.01	75.87	75.46	75.08
(Less) New Large Single Load Costs (d)	**30,492,835**	**29,297,863**	**29,244,354**	**29,086,338**	**28,938,635**
Total Contract System Cost	534,036,495	545,329,749	559,811,862	568,138,673	580,726,484
Contract System Load (MWh)					
Total Retail Load @ Meter	14,990,809	15,256,830	15,481,163	15,593,539	15,755,103
(Less) New Large Single Load	**385,440**	**385,440**	**385,440**	**385,440**	**385,440**
Total Retail Load (Net of NLSL) (d)	14,605,369	14,871,390	15,095,723	15,208,099	15,369,663
Distribution Loss (f)	1,166,538	1,187,238	1,204,695	1,213,440	1,226,012
Total Contract System Load	15,771,907	16,058,628	16,300,418	16,421,539	16,595,675
Average System Cost $/MWh	**33.86**	**33.96**	**34.34**	**34.60**	**34.99**

	Rate Period Mid-Point
Date	**4/1/09**
Fiscal Year	2009
NLSL Switch	1
Contract System Cost	
Production	470,949,913
Transmission	93,579,418
(Less) New Large Single Load Costs (d)	30,492,835
Total Contract System Cost	534,036,495
Contract System Load (MWh)	
Total Retail Load @ Meter	14,990,809
(Less) New Large Single Load	**385,440**
Total Retail Load (Net of NLSL) (d)	14,605,369
Distribution Loss (f)	1,166,538
Total Contract System Load	15,771,907
Average System Cost $/MWh	**33.86**

Tables for:

NorthWestern

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME: NorthWestern Energy - Revised
End of Year Report Period: 2006 — Amended BPA: 7-8-2008
ASC Filing Date: 5/7/2008 — Revised Amended BPA: 8-4-2008

TABLE 19A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST		19,995	-	-	19,995
Intangible Plant - Franchises and Consents	204-207	302	PTD	PTD	2,004	4	720	1,280
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST	1,175,945	-	1,140,181	35,764
Total Intangible Plant					$ 1,197,944	$ 4	$ 1,140,901	$ 57,039
Production Plant:								
Steam Production	204-207	310-317	PROD			-	-	-
Nuclear Production	204-207	320-326	PROD			-	-	-
Hydraulic Production	204-207	330-337	PROD			-	-	-
Other Production	204-207	340-347	PROD		2,646,622	2,646,622	-	-
Total Production Plant					$ 2,646,622	$ 2,646,622	$ -	$ -
Transmission Plant: (i)								
Transmission Plant	204-207	350-359.1	TRANS		446,900,651	-	446,900,651	-
Total Transmission Plant					$ 446,900,651	$ -	$ 446,900,651	$ -
Distribution Plant:								
Distribution Plant	204-207	360-374	DIST		794,846,278	-	-	794,846,278
Total Distribution Plant					$ 794,846,278	$ -	$ -	$ 794,846,278
General Plant:								
Land and Land Rights	204-207	389	PTD		402,050	855	144,389	256,806
Structures and Improvements	204-207	390	PTD		7,566,300	16,092	2,717,295	4,832,913
Furniture and Equipment	204-207	391	LABOR		1,046,919	15,591	293,365	737,963
Transportation Equipment	204-207	392	TD		25,636,266	-	9,226,408	16,409,858
Stores Equipment	204-207	393	PTD		400,192	851	143,721	255,619
Tools and Garage Equipment	204-207	394	PTD		4,018,009	8,546	1,442,993	2,566,471
Laboratory Equipment	204-207	395	PTD		3,317,020	7,055	1,191,246	2,118,720
Power Operated Equipment	204-207	396	TD		2,133,361	-	767,790	1,365,571
Communication Equipment	204-207	397	PTD		18,801,814	39,988	6,752,320	12,009,506
Miscellaneous Equipment	204-207	398	PTD		192,965	410	69,300	123,255
Other Tangible Property	204-207	399	DIRECT	PTD		-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD			-	-	-
Total General Plant					$ 63,514,896	$ 89,389	$ 22,748,825	$ 40,676,682
Total Electric Plant In-Service					$ 1,309,106,391	$ 2,736,015	$ 470,790,377	$ 835,579,999

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	NorthWestern Energy - Revised	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 19A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD			-	-	-
Nuclear Production Plant	219	108	PROD			-	-	-
Hydraulic Production Plant	219	108	PROD			-	-	-
Other Production Plant	219	108	PROD		1,945,332	1,945,332	-	-
Transmission Plant (i)	219	108	TRANS		173,762,817	-	173,762,817	-
Distribution Plant	219	108	DIST		354,798,724	-	-	354,798,724
General Plant	219	108	GP		35,207,876	49,550	12,610,236	22,548,090
Amortization of Intangible Plant - Account 301	219	111	DIST			-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST	374,185	-	362,735	11,450
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	111	DIST			-	-	-
Capital Lease - Common Plant	219	108	DIRECT			-	-	-
Leasehold Improvements	200-201	108	DIRECT	DIST		-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT		24,733,582	52,604	8,882,603	15,798,375
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST	8,258,448	-	6,924,689	1,333,759
Amortization of Acquisition Adjustments	200-201	115	DIRECT		2,821,543	-	2,821,543	-
Depreciation and Amortization Reserve (Other)			DIRECT					
Total Depreciation and Amortization Reserve					**$ 601,902,507**	**$ 2,047,487**	**$ 205,364,623**	**$ 394,490,397**
Total Net Plant					**$ 707,203,884**	**$ 688,528**	**$ 265,425,754**	**$ 441,089,602**

(Total Electric Plant In-Service) - (Total Depreciation & Amortization)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME: NorthWestern Energy - Revised

End of Year Report Period: 2006 — Amended BPA: 7-8-2008

ASC Filing Date: 5/7/2008 — Revised Amended BPA: 8-4-2008

TABLE 19A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation				13,235,775	954,336	3,322,219	8,959,219
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST			-	-	-
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD			-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST		272,720	-	-	272,720
Common Plant	356 & 356.1		DIRECT		59,321,698	126,168	21,304,277	37,891,253
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST	3,106,285	-	3,106,285	-
Total					**$ 62,700,703**	**$ 126,168**	**$ 24,410,562**	**$ 38,163,973**
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST		-	-	-
Other Investment	110-111	124	DIST			-	-	-
Long-Term Portion of Derivative Assets	110-111	175	DIST			-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST			-	-	-
Total					**$ -**	**$ -**	**$ -**	**$ -**
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD		290,330	290,330	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD			-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD		8,843,078	18,808	3,175,826	5,648,444
Merchandise (Major Only)	110-112	155	DIST			-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST			-	-	-
EPA Allowance Inventory	110-112	158.1	PROD			-	-	-
EPA Allowances Withheld	110-112	158.2	PROD			-	-	-
Stores Expense Undistributed	110-111	163	PTD			-	-	-
Prepayments	110-111	165	PTD			-	-	-
Derivative Instrument Assets	110-111	175	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST			-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST			-	-	-
Total					**$ 9,133,408**	**$ 309,138**	**$ 3,175,826**	**$ 5,648,444**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	NorthWestern Energy - Revised	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 19A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG		7,140,595	14,924	2,567,953	4,557,718
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST		-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST		-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST	94,044,791	1,748,520	23,847,708	68,448,563
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST			-	-	-
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST			-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST			-	-	-
Clearing Accounts	110-111	184	DIST		(78)	-	-	(78)
Temporary Facilities	110-111	185	PTDG		78	0	28	50
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST		-	-	-
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT					
Research, Development, and Demonstration Expenditures	110-111	188	DIST			-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG		2,934,065	6,132	1,055,170	1,872,763
Accumulated Deferred Income Taxes	110-111	190	DIST		(5,381,363)	-	-	(5,381,363)
Total					**$ 98,738,088**	**$ 1,769,576**	**$ 27,470,859**	**$ 69,497,653**
Total Assets and Other Debits					**$ 183,807,974**	**$ 3,159,218**	**$ 58,379,466**	**$ 122,269,289**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	NorthWestern Energy - Revised	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
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TABLE 19A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Liabilities and Other Credits (Comparative Balance Sheet)								
Current and Accrued Liabilites								
Derivative Instrument Liabilities	112-113	244	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST			-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Deferred Credits								
Customer Advances for Construction	112-113	252	DIST		27,216,506	-	-	27,216,506
Other Deferred Credits	112-113	253	DIRECT	DIST	39,191,290	573,882	11,454,075	27,163,334
Other Regulatory Liabilities	112-113	254	DIRECT	DIST	594,301	-	-	594,301
Accumulated Deferred Investment Tax Credits	112-113	255	DIST			-	-	-
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT					
Unamortized Gain on Reacquired Debt	112-113	257	PTDG			-	-	-
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST			-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST		62,929,457	-	-	62,929,457
Accumulated Deferred Income Taxes-Other	112-113	283	DIST		11,292,426	-	-	11,292,426
Total					**$ 141,223,980**	**$ 573,882**	**$ 11,454,075**	**$ 129,196,024**
Total Liabilities and Other Credits					**$ 141,223,980**	**$ 573,882**	**$ 11,454,075**	**$ 129,196,024**
Total Rate Base					**$ 749,787,878**	**$ 3,273,865**	**$ 312,351,145**	**$ 434,162,867**

Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	NorthWestern Energy - Revised
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 19B: Schedule 1A: Cash Working Capital (f)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	326,350,577	326,350,577	-	-
Total Transmission O&M (i)	18,891,375	-	18,891,375	-
Total Distribution O&M	27,759,804	-	-	27,759,804
Total Customer & Sales	12,512,936	-	-	12,512,936
Total Administrative and General O&M	39,448,159	360,769	7,686,380	31,401,010
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	319,076,654	319,076,654	-	-
Revised Total O&M Expenses	**$ 105,886,197**	**$ 7,634,692**	**$ 26,577,755**	**$ 71,673,750**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 13,235,775**	**$ 954,336**	**$ 3,322,219**	**$ 8,959,219**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	NorthWestern Energy - Revised	Amended BPA: 7-8-2008
End of Year Report Period:	2006	Revised Amended BPA: 8-4-2008
ASC Filing Date:	5/7/2008	

TABLE 19C: Schedule 2: Capital Structure and Rate of Return (b)

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:	11.196%
Multi-Jurisdiction Investor-Owned Utility Return Calculation:	
Consumer-Owned Utility Return Calculation:	
Rate of Return :	11.196%

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order

Note: Multi-jurisdictional utilities must begin on Page 2

Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**
Debt				3.396%
Preferred Equity				
Common Equity				
Weighted Cost of Capital	**$ 620,943.0**	**100.000%**		**8.466%**

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	**35%**
Federal Income Tax Factor	2.730%

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital	11.196%

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 749,787,878	$ 3,273,865	$ 312,351,145	$ 434,162,867
Federal Income Tax Adjusted Weighted Cost of Capital	11.196%	11.196%	11.196%	11.196%
Federal Income Tax Adjusted Return on Rate Base	**$83,947,174**	**$366,546**	**$34,971,219**	**$48,609,409**

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

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End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 19D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD		3,288,385	3,288,385	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD			-	-	-
Steam Power - Maintenance	320-323	510-515	PROD			-	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD			-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD			-	-	-
Nuclear - Maintenance	320-323	528-532	PROD			-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD			-	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD			-	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD		151,137	151,137	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD		21,120	21,120	-	-
Other Power - Maintenance	320-323	551-554.1	PROD		45,610	45,610	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	326	555	PROD		315,637,132	315,637,132	-	-
System Control and Load Dispatching	320-323	556	PROD			-	-	-
Other Expenses	320-323	557	PROD		7,207,193	7,207,193	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (a) (h)			DIRECT					
Total Production Expense					**$ 326,350,577**	**$ 326,350,577**	**$ -**	**$ -**
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS		5,375,034	-	5,375,034	-
Total Operations less Wheeling	320-323	560-567.1	TRANS		8,173,157	-	8,173,157	-
Total Maintenance	320-323	568-574	TRANS		5,343,184	-	5,343,184	-
Total Transmission Expense					**$ 18,891,375**	**$ -**	**$ 18,891,375**	**$ -**

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RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME: NorthWestern Energy - Revised
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ASC Filing Date: 5/7/2008 — Revised Amended BPA: 8-4-2008

TABLE 19D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Distribution Expense:								
Total Operations	320-323	580-589	DIST		13,558,310	-	-	13,558,310
Total Maintenance	320-323	590-598	DIST		14,201,494	-	-	14,201,494
Total Distribution Expense					$ 27,759,804	$ -	$ -	$ 27,759,804
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST		8,115,487	-	-	8,115,487
Customer Service and Information	320-323	906-907	DIST			-	-	-
Customer Assistance Expenses (Major only)	320-323	908	DIRECT		2,364,425			2,364,425
Customer Service and Information	320-323	909-910	DIST		1,147,618	-	-	1,147,618
Total Sales Expense	320-323	911-917	DIST		885,406	-	-	885,406
Total Customer and Sales Expenses					$ 12,512,936	$ -	$ -	$ 12,512,936
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR		13,190,325	196,434	3,696,156	9,297,735
Office Supplies & Expenses	320-323	921	LABOR		3,968,078	59,094	1,111,924	2,797,061
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR		3,691,830	54,980	1,034,514	2,602,336
Outside Services Employed (g)	320-323	923	LABOR		4,042,391	60,200	1,132,748	2,849,443
Property Insurance	320-323	924	PTDG		523,235	1,094	188,170	333,972
Injuries and Damages	320-323	925	LABOR		2,681,978	39,941	751,536	1,890,501
Employee Pensions & Benefits	320-323	926	LABOR		3,543,720	52,774	993,011	2,497,935
Franchise Requirements	320-323	927	DIST			-	-	-
Regulatory Commission Expenses	320-323	928	DIST		1,120,878	-	-	1,120,878
(Less) Duplicate Charges - Credit	320-323	929	PTDG			-	-	-
General Advertising Expenses (g)	320-323	930.1	DIST	DIST	9,131	-	-	9,131
Miscellaneous General Expenses	320-323	930.2	DIST		10,688,250	-	-	10,688,250
Rents	320-323	931	DIST		992,736	-	-	992,736
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM		2,379,267	6,212	847,349	1,525,706
Total Administration and General Expenses					$ 39,448,159	$ 360,769	$ 7,686,380	$ 31,401,010

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME: NorthWestern Energy - Revised
End of Year Report Period: 2006 — Amended BPA: 7-8-2008
ASC Filing Date: 5/7/2008 — Revised Amended BPA: 8-4-2008

TABLE 19D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Total Operations and Maintenance					$ 424,962,851	$ 326,711,346	$ 26,577,755	$ 71,673,750
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST	45,848	-	39,349	6,499
Steam Production Plant	336	403	PROD			-	-	-
Nuclear Production Plant	336	403	PROD			-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD			-	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD			-	-	-
Other Production Plant	336	403	PROD		107,690	107,690	-	-
Transmission Plant (i)	336	403	TRANS		12,426,976	-	12,426,976	-
Distribution Plant	336	403	DIST		28,567,724	-	-	28,567,724
General Plant	336	403	GP		3,320,747	4,674	1,189,376	2,126,697
Common Plant - Electric	336	403	DIRECT		1,586,760	3,375	569,855	1,013,530
Common Plant - Electric	336	404	DIRECT		2,383,559	5,069	856,011	1,522,479
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT					
Amortization of Limited Term Electric Plant	336	404	DIRECT					
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIRECT		94,914		94,914	
Total Depreciation and Amortization					$ 48,534,218	$ 120,808	$ 15,176,481	$ 33,236,931
Total Operating Expenses					$ 473,497,069	$ 326,832,154	$ 41,754,236	$ 104,910,681
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

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TABLE 19E: Schedule 3A Items: Taxes

Account Description	FERC Form 1		Funct. Method	Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers					
FEDERAL							
Income Tax	262	409.1	DIST	20,490,886	-	-	20,490,886
Employment Tax	262	408.1	LABOR	2,815,525	41,930	788,959	1,984,637
Other Federal Taxes	262	408.1	DIST	11,172	-	-	11,172
TOTAL FEDERAL				**$ 23,317,583**	**$ 41,930**	**$ 788,959**	**$ 22,486,695**
STATE AND OTHER							
Property or In-Lieu (c)	262	408.1	PTDG	49,880,451	104,249	17,938,371	31,837,830
Unemployment	262	408.1	LABOR	14,588	217	4,088	10,283
State Income, B&O, etc.	262	409.1	DIST	2,568,678	-	-	2,568,678
Franchise Fees	262	408.1	DIST	5,337	-	-	5,337
Regulatory Commission	262	408.1	DIST	1,655,658	-	-	1,655,658
City/Municipal	262	408.1	DIST		-	-	-
Other	262	408.1	DIST	1,439,624	-	-	1,439,624
TOTAL STATE AND OTHER TAXES				**$ 55,564,336**	**$ 104,467**	**$ 17,942,459**	**$ 37,517,410**
TOTAL TAXES				**$ 78,881,919**	**$ 146,396**	**$ 18,731,418**	**$ 60,004,105**

BONNEVILLE POWER ADMINISTRATION
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ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 19F: Schedule 3B Other Included Items (j)

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD		-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST	7,271,890	480,378	2,983,400	3,808,113
Gain from Disposition of Utility Plant	114	411.6	DIRECT	PROD		-	-	-
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST		-	-	-
Gain from Disposition of Allowances	114	411.8	PROD			-	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD			-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD		-	-	-
Total Other Included Items					$ (7,271,890)	$ (480,378)	$ (2,983,400)	$ (3,808,113)
Sales for Resale:								
Sales for Resale	310	447	PROD		47,339,878	47,339,878	-	-
Total Sales for Resale					$ 47,339,878	$ 47,339,878	$ -	$ -
Other Revenues:								
Forfeited Discounts	300	450	DIST		8,000	-	-	8,000
Miscellaneous Service Revenues	300	451	DIST			-	-	-
Sales of Water and Water Power	300	453	PROD			-	-	-
Rent from Electric Property	300	454	TD		2,321,729	-	835,583	1,486,146
Interdepartmental Rents	300	455	DIST			-	-	-
Other Electric Revenues	300	456	DIRECT	PROD	12,394,297	1,014,520	9,925,393	1,454,384
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS		34,983,334	-	34,983,334	-
Total Other Revenues					$ 49,707,360	$ 1,014,520	$ 45,744,310	$ 2,948,530
Total Other Included Items					$ 89,775,348	$ 47,874,020	$ 42,760,910	$ (859,583)
(Total Other + Total Sales for Resale + Total Other Revenue)								

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	NorthWestern Energy - Revised	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 19G: Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses *(From Schedule 3)*	$ 473,497,069	$ 326,832,154	$ 41,754,236	$ 104,910,681
Federal Income Tax Adjusted Return on Rate Base *(From Schedule 2)*	$ 83,947,174	$ 366,546	$ 34,971,219	$ 48,609,409
State and Other Taxes *(From Schedule 3a)*	$ 78,881,919	$ 146,396	$ 18,731,418	$ 60,004,105
Total Other Included Items *(From Schedule 3b)*	$ 89,775,348	$ 47,874,020	$ 42,760,910	$ (859,583)
Total Cost	**$ 546,550,814**	**$ 279,471,076**	**$ 52,695,962**	**$ 214,383,778**

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	NorthWestern Energy - Revised	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended BPA: 8-4-2008

TABLE 19G: Schedule 4: Average System Cost

Contract System Cost	
Production	$ 279,471,076
Transmission	$ 52,695,962
(Less) New Large Single Load Costs (d)	
Total Contract System Cost	**$ 332,167,038**
Contract System Load (MWh)	
Total Retail Load	5,749,741
(Less) New Large Single Load	
Total Retail Load (Net of NLSL) (d)	5,749,741
Distribution Loss (e)	463,651
Total Contract System Load	**6,213,392**
Average System Cost $/MWh	**53.46**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	NorthWestern Energy - Revised
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 19H: Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	522,818
Transmission	354-355	3,705,809
Distribution	354-355	7,706,480
Customer Accounts	354-355	2,259,154
Customer Service and Information	354-355	2,168,867
Sales	354-355	59,981
Administrative and General	354-355	11,372,633
TOTAL Operation		**$27,795,742**
Maintenance		
Production	354-355	18,206
Transmission	354-355	2,190,807
Distribution	354-355	6,191,052
Administrative and General	354-355	2,050,386
TOTAL Maintenance		**$10,450,451**
Operation and Maintenance		
Production (Total of lines 16 and 26)	354-355	541,024
Transmission (Total of lines 17 and 27)	354-355	5,896,616
Distribution (Total of lines 18 and 28)	354-355	13,897,532
Customer Accounts (From line 20)	354-355	2,259,154
Customer Service and Information (From line 20)	354-355	2,168,867
Sales (From line 21)	354-355	59,981
Administrative and General (Total of lines 22 and 29)	354-355	13,423,019
TOTAL Operation and Maintenance		**$38,246,193**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	NorthWestern Energy - Revised
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 19I: Ratio Table

Labor Ratio Input:

	Ratio Used	Total	Production	Transmission	Distribution
Production	PROD	$ 541,024	$ 541,024	$ -	$ -
Transmission	TRANS	5,896,616	-	5,896,616	-
Distribution	DIST	13,897,532	-	-	13,897,532
Customer Accounts	DIST	2,259,154	-	-	2,259,154
Customer Service and Informational	DIRECT	2,168,867	-	-	2,168,867
Sales	DIST	59,981	-	-	59,981
Administrative & General	PTD	13,423,019	28,549	4,820,626	8,573,844
Total Labor		$ 38,246,193	$ 569,573	$ 10,717,242	$ 26,959,378
LABOR RATIO		**100%**	**1.49%**	**28.02%**	**70.49%**

GP	Ratio Used	Total	Production	Transmission	Distribution
General Plant Ratio					
Land and Land Rights	PTD	$ 402,050	$ 855	$ 144,389	$ 256,806
Structures and Improvements	PTD	7,566,300	16,092	2,717,295	4,832,913
Furniture and Equipment	LABOR	1,046,919	15,591	293,365	737,963
Transportation Equipment	TD	25,636,266	-	9,226,408	16,409,858
Stores Equipment	PTD	400,192	851	143,721	255,619
Tools and Garage Equipment	PTD	4,018,009	8,546	1,442,993	2,566,471
Laboratory Equipment	PTD	3,317,020	7,055	1,191,246	2,118,720
Power Operated Equipment	TD	2,133,361	-	767,790	1,365,571
Communication Equipment	PTD	18,801,814	39,988	6,752,320	12,009,506
Miscellaneous Equipment	PTD	192,965	410	69,300	123,255
Other Tangible Property	DIRECT	-	-	-	-
Asset Retirement Costs for General Plant	PTD	-	-	-	-
TOTAL		$ 63,514,896	$ 89,389	$ 22,748,825	$ 40,676,682
GP RATIO		**100%**	**0.14%**	**35.82%**	**64.04%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	NorthWestern Energy - Revised
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 19I: Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
PTD	**Production, Transmission, Distribution Ratio**					
	Steam Production	PROD	$ -	$ -	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	-	-	-	-
	Other Production	PROD	2,646,622	2,646,622	-	-
	Total Production Plant		2,646,622	2,646,622	-	-
	Transmission Plant	TRANS	446,900,651	-	446,900,651	-
	Total Distribution Plant	DIST	794,846,278	-	-	794,846,278
	TOTAL		$ 1,244,393,551	$ 2,646,622	$ 446,900,651	$ 794,846,278
	PTD RATIO		**100%**	**0.21%**	**35.91%**	**63.87%**

		Ratio Used	Total	Production	Transmission	Distribution
PTDG	**Production, Transmission, Distribution and General Plant Ratio**					
	PTD Total		$ 1,244,393,551	$ 2,646,622	$ 446,900,651	$ 794,846,278
	Intangible Plant - Organization	DIST	19,995	-	-	19,995
	Intangible Plant - Franchises and Consents	DIRECT	2,004	4	720	1,280
	Intangible Plant - Miscellaneous	DIRECT	1,175,945	-	1,140,181	35,764
	General Plant Total		63,514,896	89,389	22,748,825	40,676,682
	TOTAL		$ 1,309,106,391	$ 2,736,015	$ 470,790,377	$ 835,579,999
	PTDG RATIO		**100%**	**0.21%**	**35.96%**	**63.83%**

		Ratio Used	Total	Production	Transmission	Distribution
TD	**Transmission and Distribution Plant Ratio**					
	Total Transmission Plant	TRANS	$ 446,900,651	$ -	$ 446,900,651	$ -
	Total Distribution Plant	DIST	794,846,278	-	-	794,846,278
	TOTAL		$ 1,241,746,929	$ -	$ 446,900,651	$ 794,846,278
	TD RATIO		**100%**	**0.00%**	**35.99%**	**64.01%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	NorthWestern Energy - Revised
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 19I: Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
GPM	**Maintenance of General Plant Ratio**					
	Structures and Improvements	PTD	$ 7,566,300	$ 16,092	$ 2,717,295	$ 4,832,913
	Furniture and Equipment	LABOR	1,046,919	15,591	293,365	737,963
	Communication Equipment	PTD	18,801,814	39,988	6,752,320	12,009,506
	Miscellaneous Equipment	PTD	192,965	410	69,300	123,255
	TOTAL		$ 27,607,998	$ 72,082	$ 9,832,279	$ 17,703,637
	GPM RATIO		**100%**	**0.26%**	**35.61%**	**64.13%**

SUMMARY RATIO TABLE

Direct to Distribution	**DIST**	**0.00%**	**0.00%**	**100.00%**
Direct to Production	**PROD**	**100.00%**	**0.00%**	**0.00%**
Direct to Transmission	**TRANS**	**0.00%**	**100.00%**	**0.00%**
Direct Allocation	**DIRECT**	**0.00%**	**0.00%**	**0.00%**
General Plant	**GP**	**0.14%**	**35.82%**	**64.04%**
Maintenance of General Plant	**GPM**	**0.26%**	**35.61%**	**64.13%**
Labor Ratios	**LABOR**	**1.49%**	**28.02%**	**70.49%**
Production, Transmission, Distribution	**PTD**	**0.21%**	**35.91%**	**63.87%**
Production, Transmission, Distribution, General	**PTDG**	**0.21%**	**35.96%**	**63.83%**
Transmission, Distribution	**TD**	**0.00%**	**35.99%**	**64.01%**

BONNEVILLE POWER ADMINSTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

TABLE 19J

UTILITY NAME:	NorthWestern Energy - Revised
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

FERC Form 1		Purchased Power - Base Period		Purchased Power - Base Period Minus 1		Purchased Power - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
RQ	326-327	$ 21,452,392	286,516				
LF	326-327	$ 118,386,444	3,536,694				
IF	326-327	$ -	-				
SF	326-327	$ 103,536,270	2,156,156				
LU	326-327	$ 67,719,154	1,290,616				
IU	326-327	$ 117,976	3,719				
OS	326-327	$ 4,324,286	800				
EX	326-327	$ 100,610	1,922				
NA	326-327	$ -	-				
AD	326-327	$ -	-				
TOTAL		**$ 315,637,132**	**7,276,423**	$ -	-	$ -	-

FERC Form 1		Sales for Resale - Base Period		Sales for Resale - Base Period Minus 1		Sales for Resale - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Sold	Settlement Total	MWh Sold	Settlement Total	MWh Sold
RQ	310-311	$ -	-				
LF	310-311	$ -	-				
IF	310-311	$ -	-				
SF	310-311	$ 47,339,878	1,267,830				
LU	310-311	$ -	-				
IU	310-311	$ -	-				
OS	310-311	$ -	-				
EX	310-311	$ -	-				
NA	310-311	$ -	-				
AD	310-311	$ -	-				
TOTAL		**$ 47,339,878**	**1,267,830**	$ -	-	$ -	-

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TABLE 19K: Forecasted Contract System Costs & ASC with New Additions and NLSL

Date	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
	6	7	8	9	10
Fiscal Year	2009	2010	2011	2012	2013
Rate Period Mid-Point	**TRUE**	**FALSE**	**FALSE**	**FALSE**	**FALSE**
Contract System Cost					
Production	325,602,601	343,066,995	362,474,784	383,344,870	405,615,201
Transmission	49,773,010	48,305,130	46,859,814	45,371,968	43,907,962
NLSL Fully Allocated Cost ($/MWh)					
(Less) New Large Single Load Costs (d)	**0**	**0**	**0**	**0**	**0**
Total Contract System Cost	375,375,611	391,372,125	409,334,598	428,716,838	449,523,163
Contract System Load (MWh)					
Total Retail Load @ Meter	6,334,276	6,542,040	6,756,619	6,978,236	7,207,122
(Less) New Large Single Load	**0**	**0**	**0**	**0**	**0**
Total Retail Load (Net of NLSL) (d)	6,334,276	6,542,040	6,756,619	6,978,236	7,207,122
Distribution Loss (f)	510,787	527,540	544,844	562,715	581,172
Total Contract System Load	6,845,062	7,069,580	7,301,463	7,540,951	7,788,294
Average System Cost $/MWh	**54.84**	**55.36**	**56.06**	**56.85**	**57.72**

	Rate Period Mid-Point
Date	**4/1/09**
Fiscal Year	2009
NLSL Switch	1
Contract System Cost	
Production	325,602,601
Transmission	49,773,010
(Less) New Large Single Load Costs (d)	0
Total Contract System Cost	375,375,611
Contract System Load (MWh)	
Total Retail Load @ Meter	6,334,276
(Less) New Large Single Load	**0**
Total Retail Load (Net of NLSL) (d)	6,334,276
Distribution Loss (f)	510,787
Total Contract System Load	6,845,062
Average System Cost $/MWh	**54.84**

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Tables for:

PacifiCorp

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 20A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST		$0	$0	$0	$0
Intangible Plant - Franchises and Consents	204-207	302	**DIRECT**	**PTD**	$51,880,743	$50,880,743	$0	$1,000,000
Intangible Plant - Miscellaneous	204-207	303	**DIRECT**	**DIST**	$244,725,490	$122,368,003	$46,177,570	$76,179,916
Total Intangible Plant					**$296,606,233**	**$173,248,746**	**$46,177,570**	**$77,179,916**
Production Plant:								
Steam Production	204-207	310-316	PROD		$2,066,689,427	$2,066,689,427	$0	$0
Nuclear Production	204-207	320-325	PROD		$0	$0	$0	$0
Hydraulic Production	204-207	330-336	PROD		$233,341,208	$233,341,208	$0	$0
Other Production	204-207	340-346	PROD		$348,799,787	$348,799,787	$0	$0
Total Production Plant					**$2,648,830,422**	**$2,648,830,422**	**$0**	**$0**
Transmission Plant: (i)								
Transmission Plant	204-207	350-359	TRANS		$1,160,939,950	$0	$1,160,939,950	$0
Total Transmission Plant					**$1,160,939,950**	**$0**	**$1,160,939,950**	**$0**
Distribution Plant:								
Distribution Plant	204-207	360-373	DIST		$2,083,832,056	$0	$0	$2,083,832,056
Total Distribution Plant					**$2,083,832,056**	**$0**	**$0**	**$2,083,832,056**
General Plant:								
Land and Land Rights	204-207	389	PTD		$6,170,540	$2,773,298	$1,215,492	$2,181,750
Structures and Improvements	204-207	390	PTD		$105,236,114	$47,297,493	$20,729,734	$37,208,887
Furniture and Equipment	204-207	391	LABOR		$46,835,393	$21,374,409	$4,089,791	$21,371,193
Transportation Equipment	204-207	392	TD		$40,859,704	$0	$14,619,105	$26,240,599
Stores Equipment	204-207	393	PTD		$5,341,312	$2,400,608	$1,052,148	$1,888,556
Tools and Garage Equipment	204-207	394	PTD		$26,417,572	$11,873,157	$5,203,815	$9,340,600
Laboratory Equipment	204-207	395	PTD		$17,955,617	$8,070,002	$3,536,953	$6,348,662
Power Operated Equipment	204-207	396	TD		$54,030,242	$0	$19,331,363	$34,698,878
Communication Equipment	204-207	397	PTD		$109,518,404	$49,222,132	$21,573,272	$38,722,999
Miscellaneous Equipment	204-207	398	PTD		$2,440,871	$1,097,029	$480,810	$863,032
Other Tangible Property	204-207	399	**DIRECT**	**PTD**	$146,618,604	$146,618,604	$0	$0
Asset Retirement Costs for General Plant	204-208	399.1	PTD		$17,834	$8,015	$3,513	$6,306
Total General Plant					**$561,442,204**	**$290,734,747**	**$91,835,996**	**$178,871,461**
Total Electric Plant In-Service					**$6,751,650,866**	**$3,112,813,916**	**$1,298,953,516**	**$2,339,883,434**

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 20A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD		$1,034,032,280	$1,034,032,280	$0	$0
Nuclear Production Plant	219	108	PROD		$0	$0	$0	$0
Hydraulic Production Plant	219	108	PROD		$102,071,815	$102,071,815	$0	$0
Other Production Plant	219	108	PROD		$33,411,091	$33,411,091	$0	$0
Transmission Plant (i)	219	108	TRANS		$441,365,990	$0	$441,365,990	$0
Distribution Plant	219	108	DIST		$859,835,513	$0	$0	$859,835,513
General Plant	219	108	GP		$208,525,197	$107,981,766	$34,108,799	$66,434,633
Amortization of Intangible Plant - Account 301	219	111	DIST		$800,066	$0	$0	$800,066
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD	$7,470,771	$7,470,771	$0	$0
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST	$141,543,321	$70,774,702	$26,707,993	$44,060,626
Mining Plant Depreciation	219	108	PROD		$61,024,761	$61,024,761	$0	$0
Amortization of Plant Held for Future Use	219	108	DIST		$0	$0	$0	$0
Capital Lease - Common Plant	219	108	DIRECT		$12,788,585	$5,747,723	$2,519,135	$4,521,728
Leasehold Improvements	200-201	108	DIRECT	DIST	$198,800	$0	$0	$198,800
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT		$0	$0	$0	$0
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST	$204,992,462	$0	$0	$204,992,462
Amortization of Acquisition Adjustments	200-201	115	DIRECT		$34,493,002	$34,493,002	$0	$0
Depreciation and Amortization Reserve (Other)			DIRECT	DIRECT	$0	$0	$0	$0
Total Depreciation and Amortization Reserve					**$3,142,553,655**	**$1,457,007,911**	**$504,701,916**	**$1,180,843,828**
Total Net Plant					**$3,609,097,210**	**$1,655,806,005**	**$794,251,599**	**$1,159,039,606**

(Total Electric Plant In-Service) - (Total Depreciation & Amortization)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008TA

TABLE 20A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation: Automatic Input from Sch 1A				$60,857,514	$26,430,377	$8,498,553	$25,928,584
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST		$458,848	$0	$0	$458,848
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD		$13,585,451	$6,105,868	$2,676,104	$4,803,479
Nuclear Fuel		120.1-120.6	PROD		$0	$0	$0	$0
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST		$308,529,167	$0	$0	$308,529,167
Common Plant	356 & 356.1		DIRECT		$0	$0	$0	$0
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST	$67,870,395	$67,870,395	$0	$0
Total					**$390,443,861**	**$73,976,263**	**$2,676,104**	**$313,791,495**
Other Property and Investments								
Investment in Associated Companies	110-111	123	DIRECT	DIST	$0	$0	$0	$0
Other Investment	110-111	124	DIST		$32,276,463	$0	$0	$32,276,463
Long-Term Portion of Derivative Assets	110-111	175	DIST		$98,686,953	$0	$0	$98,686,953
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST		$0	$0	$0	$0
Total					**$130,963,416**	**$0**	**$0**	**$130,963,416**
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD		$34,554,273	$34,554,273	$0	$0
Fuel Stock Expenses Undistributed	110-111	152	PROD		$0	$0	$0	$0
Plant Materials and Operating Supplies	110-111	154	PTD		$58,101,435	$26,113,205	$11,445,000	$20,543,231
Merchandise (Major Only)	110-112	155	DIST		$0	$0	$0	$0
Other Materials and Supplies (Major only)	110-111	156	DIST		$0	$0	$0	$0
EPA Allowance Inventory	110-112	158.1	PROD		$0	$0	$0	$0
EPA Allowances Withheld	110-112	158.2	PROD		$0	$0	$0	$0
Stores Expense Undistributed	110-111	163	PTD		$0	$0	$0	$0
Prepayments	110-111	165	PTD		$36,224,542	$16,280,818	$7,135,622	$12,808,102
Derivative Instrument Assets	110-111	175	DIST		$160,205,097	$0	$0	$160,205,097
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST		($98,686,953)	$0	$0	($98,686,953)
Derivative Instrument Assets - Hedges	110-111	176	DIST		$1,884,369	$0	$0	$1,884,369
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST		$0	$0	$0	$0
Total					**$389,656,671**	**$76,948,296**	**$18,580,621**	**$294,127,753**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 20A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG		$9,974,822	$4,598,840	$1,919,061	$3,456,920
Extraordinary Property Losses	110-111	182.1	DIST	DIST	$0	$0	$0	$0
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIST	DIST	$2,197,477	$0	$0	$2,197,477
Other Regulatory Assets	110-111	182.3	DIST	DIST	$601,331,021	$37,172,237	$5,296,038	$558,862,746
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST		$1,565,792	$0	$0	$1,565,792
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST		$0	$0	$0	$0
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST		$0	$0	$0	$0
Clearing Accounts	110-111	184	DIST		$0	$0	$0	$0
Temporary Facilities	110-111	185	PTDG		$15,347	$7,076	$2,953	$5,319
Miscellaneous Deferred Debits	110-111	186	DIST	DIST	$22,345,790	$16,322,566	$0	$6,023,224
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT	DIRECT	$0	$0	$0	$0
Research, Development, and Demonstration Expenditures	110-111	188	DIST		$0	$0	$0	$0
Unamortized Loss on Reacquired Debt	110-111	189	PTDG		$10,685,987	$4,926,719	$2,055,882	$3,703,385
Accumulated Deferred Income Taxes	110-111	190	DIST		$321,060,388	$0	$0	$321,060,388
Total					**$969,176,624**	**$63,027,438**	**$9,273,934**	**$896,875,252**
Total Assets and Other Debits					**$1,941,098,087**	**$240,382,375**	**$39,029,212**	**$1,661,686,500**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 20A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Liabilities and Other Credits (Comparative Balance Sheet)								
CURRENT AND ACCRUED LIABILITIES								
Derivative Instrument Liabilities	112-113	244	DIST		$257,447,785	$0	$0	$257,447,785
(less) Long-Term Portion of Derivative Instrument Liabilit	112-114	244	DIST		$211,934,075	$0	$0	$211,934,075
Derivative Instrument Liabilities - Hedges	112-115	245	DIST		$498,360	$0	$0	$498,360
(less) Long-Term Portion of Derivative Instrument Liabilit	112-114	245	DIST		$0	$0	$0	$0
Total					**$46,012,070**	**$0**	**$0**	**$46,012,070**
DEFERRED CREDITS								
					$0	$0	$0	$0
					$0	$0	$0	$0
Customer Advances for Construction	112-113	252	DIST		$4,178,614	$0	$0	$4,178,614
Other Deferred Credits	112-113	253	DIST	DIST	$49,127,992	$6,437,915	$45,922	$42,644,155
Other Regulatory Liabilities	112-113	254	DIST	DIST	$46,201,388	$569,243	$249,490	$45,382,654
Accumulated Deferred Investment Tax Credits	112-113	255	DIST		$26,895,763	$0	$0	$26,895,763
Deferred Gains from Disposition of Utility Plant	112-113	256	PTD	DIRECT	$0	$0	$0	$0
Unamortized Gain on Reacquired Debt	112-113	257	PTDG		$23,594	$10,878	$4,539	$8,177
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST		$215,843	$0	$0	$215,843
Accumulated Deferred Income Taxes-Property	112-113	282	DIST		$876,901,340	$0	$0	$876,901,340
Accumulated Deferred Income Taxes-Other	112-113	283	DIST		$177,021,283	$0	$0	$177,021,283
Total					**$1,180,565,817**	**$7,018,036**	**$299,951**	**$1,173,247,829**
Total Liabilities and Other Credits					**$1,226,577,887**	**$7,018,036**	**$299,951**	**$1,219,259,899**
Total Rate Base					**$4,323,617,410**	**$1,889,170,344**	**$832,980,860**	**$1,601,466,207**
(Total Net Plant + Debits - Credits)								

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp	Amended 7-8-2008
End of Year Report Period:	2006	Revised Amended 8-4-2008
ASC Filing Date:		

*TABLE 20B: **Schedule 1A: Cash Working Capital (f)***

(Automatic Input from Schedule 3- Expenses)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	799,907,271	798,749,315	-	1,157,956
Total Transmission O&M (i)	59,052,235	-	59,052,235	-
Total Distribution O&M	94,476,304	-	-	94,476,304
Total Customer & Sales	63,551,136	8,942,346	-	54,608,789
Total Administrative and General O&M	105,926,442	38,646,675	8,936,187	58,343,580
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	636,053,276	634,895,320	-	1,157,956
Revised Total O&M Expenses	**$ 486,860,112**	**$ 211,443,017**	**$ 67,988,422**	**$ 207,428,673**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 60,857,514**	**$ 26,430,377**	**$ 8,498,553**	**$ 25,928,584**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Oregon
End of Year Report Period:	2006
ASC Filing Date:	

TABLE 20B: Schedule 1A: Cash Working Capital (f)

(Automatic Input from Schedule 3- Expenses)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	534,127,125	532,969,170	-	1,157,956
Total Transmission O&M (i)	39,082,112	-	39,082,112	-
Total Distribution O&M	69,089,334	-	-	69,089,334
Total Customer & Sales	39,720,011	60,362	-	39,659,649
Total Administrative and General O&M	74,863,187	26,361,802	6,096,301	42,405,084
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	425,743,737	424,585,781	-	1,157,956
Revised Total O&M Expenses	**$ 331,138,032**	**$ 134,805,552**	**$ 45,178,413**	**$ 151,154,066**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 41,392,254**	**$ 16,850,694**	**$ 5,647,302**	**$ 18,894,258**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Washington
End of Year Report Period:	2006
ASC Filing Date:	

TABLE 20B: Schedule 1A: Cash Working Capital (f)

(Automatic Input from Schedule 3- Expenses)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	148,900,658	148,900,658	-	-
Total Transmission O&M (i)	11,318,366	-	11,318,366	-
Total Distribution O&M	14,031,069	-	-	14,031,069
Total Customer & Sales	16,058,145	6,410,255	-	9,647,890
Total Administrative and General O&M	17,905,526	7,096,565	1,639,014	9,169,946
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	117,582,733	117,582,733	-	-
Revised Total O&M Expenses	**$ 90,631,030**	**$ 44,824,744**	**$ 12,957,381**	**$ 32,848,905**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 11,328,879**	**$ 5,603,093**	**$ 1,619,673**	**$ 4,106,113**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Idaho
End of Year Report Period:	2006
ASC Filing Date:	

TABLE 20B: Schedule 1A: Cash Working Capital (f)

(Automatic Input from Schedule 3- Expenses)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	116,879,488	116,879,488	-	-
Total Transmission O&M (i)	8,651,757	-	8,651,757	-
Total Distribution O&M	11,355,901	-	-	11,355,901
Total Customer & Sales	7,772,980	2,471,730	-	5,301,251
Total Administrative and General O&M	13,157,730	5,188,308	1,200,872	6,768,550
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	92,726,806	92,726,806	-	-
Revised Total O&M Expenses	**$ 65,091,050**	**$ 31,812,720**	**$ 9,852,628**	**$ 23,425,701**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 8,136,381**	**$ 3,976,590**	**$ 1,231,579**	**$ 2,928,213**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended 8-4-2008

TABLE 20C: Schedule 2: Capital Structure and Rate of Return (b)

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:	0.000%
Multi-Jurisdiction Investor-Owned Utility Return Calculation:	10.865%
Consumer-Owned Utility Return Calculation:	0.000%
Rate of Return :	10.865%

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order

Note: Multi-jurisdictional utilities must begin on Page 2

Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	Amount	Percent	Embedded	Weighted
Debt		0.0%		0.000%
Preferred Equity		0.0%		0.000%
Common Equity		0.0%		0.000%
Weighted Cost of Capital	$ -	0.000%		0.000%

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	35%	
Federal Income Tax Factor		0.000%

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital	0.000%

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 4,323,617,410	$ 1,889,170,344	$ 832,980,860	$ 1,601,466,207
Federal Income Tax Adjusted Weighted Cost of Capital	0.000%	0.000%	0.000%	0.000%
Federal Income Tax Adjusted Return on Rate Base	$0	$0	$0	$0

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended 8-4-2008

TABLE 20C: Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation

Step 1:

Weighted Cost of Capital from Most Recent State Commission Rate Order in IDAHO:

	Capitalization Structure		Effective Cost		Jurisdictional	Effective Cost -	
Component	Amount	Percent	Embedded	Weighted	Allocation	Weighted	State Allocation
Debt		49.1%	6.26%	3.074%	14.59%	0.45%	7.163%
Preferred Equity		0.5%	5.41%	0.028%		0.00%	0.07%
Common Equity		50.4%	10.25%	5.166%		0.75%	7.35%
Weighted Cost of Capital	$ -	100.00%		8.268%		1.21%	14.59%

Weighted Cost of Capital from Most Recent State Commission Rate Order in OREGON:

Component	Amount	Percent	Embedded	Weighted			
Debt		49.0%	6.33%	3.102%	66.49%	2.06%	32.582%
Preferred Equity		1.0%	6.30%	0.063%		0.04%	0.66%
Common Equity		50.0%	10.00%	5.000%		3.32%	33.25%
Weighted Cost of Capital	$ -	100.00%		8.165%		5.43%	66.49%

Weighted Cost of Capital from Most Recent State Commission Rate Order in WASHINGTON:

Component	Amount	Percent	Embedded	Weighted			
Debt		53.0%	6.23%	3.302%	18.92%	0.62%	10.026%
Preferred Equity		1.0%	6.46%	0.065%		0.01%	0.189%
Common Equity		46.0%	10.20%	4.692%		0.89%	8.701%
Weighted Cost of Capital	$ -	100.00%		8.059%		1.52%	18.92%

Jurisdiction	Rate Base	Weighted cost	%	Weighted Return		
IDAHO	$397,150,011	8.27%	1.21%	$32,407,346		1.21%
OREGON	1,810,073,974	8.17%	5.43%	147,701,604		5.43%
WASHINGTON	514,927,219	8.06%	1.52%	42,017,938		1.52%
Total	$2,722,151,204		8.16%	$222,126,887	100.00%	8.16%

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended 8-4-2008

TABLE 20C: Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation *(continued)*

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	**35%**	
Federal Income Tax Factor		**2.705%**
*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*		
Federal Income Tax Adjusted Weighted Cost of Capital		**10.865%**
(Weighted Cost of Capital Plus Federal Income Tax Factor)		

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 4,323,617,410	$ 1,889,170,344	$ 832,980,860	$ 1,601,466,207
Federal Income Tax Adjusted Weighted Cost of Capital	10.865%	10.865%	10.865%	10.865%
Federal Income Tax Adjusted Return on Rate Base	**$469,775,302**	**$205,264,593**	**$90,506,120**	**$174,004,589**
*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*				

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended 8-4-2008

TABLE 20C: Schedule 2: Capital Structure and Rate of Return (b)

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

Debt Issue	Original Amount	Year Issued	Year Due	Interest Rate	Interest Expense
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	$ -			0.00%	$ -

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 4,323,617,410	$ 1,889,170,344	$ 832,980,860	$ 1,601,466,207
Weighted Cost of Debt	0%	0%	0%	0%
Return on Rate Base	$0	$0	$0	$0

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME: PacifiCorp
End of Year Report Period: 2006 — Amended 7-8-2008
ASC Filing Date: 5/7/2008 — Revised Amended 8-4-2008

TABLE 20D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD		203,929,787	203,929,787	0	0
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD		40,668,013	40,668,013	0	0
Steam Power - Maintenance	320-323	510-515	PROD		69,751,506	69,751,506	0	0
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD		0	0	0	0
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD		0	0	0	0
Nuclear - Maintenance	320-323	528-532	PROD		0	0	0	0
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540	PROD		12,219,562	12,219,562	0	0
Hydraulic - Maintenance	320-323	541-545	PROD		2,590,238	2,590,238	0	0
Other Power Generation								
Other Power - Fuel	320-323	547	PROD		54,215,329	54,215,329	0	0
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550	PROD		12,701,471	12,701,471	0	0
Other Power - Maintenance	320-323	551-554	PROD		1,389,926	1,389,926	0	0
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	320-323	555	PROD		352,175,806	352,175,806	0	0
System Control and Load Dispatching	320-323	556	PROD		1,072,686	1,072,686	0	0
Other Expenses	320-323	557	PROD		23,460,594	23,460,594	0	0
BPA REP Reversal	327	555	PROD		0	0	0	0
Public Purpose Charges (h)			CONS		25,732,354	24,574,398	0	1,157,956
Total Production Expense					**$ 799,907,271**	**$ 798,749,315**	**$ -**	**$ 1,157,956**
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS		40,564,227	0	40,564,227	0
Total Operations less Wheeling	320-323	560-567	TRANS		8,308,460	0	8,308,460	0
Total Maintenance	320-323	568-573	TRANS		10,179,549	0	10,179,549	0
Total Transmission Expense					**$ 59,052,235**	**$ -**	**$ 59,052,235**	**$ -**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME: PacifiCorp
End of Year Report Period: 2006 Amended 7-8-2008
ASC Filing Date: 5/7/2008 Revised Amended 8-4-2008

TABLE 20D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Distribution Expense:								
Total Operations	320-323	580-589	DIST		37,493,123	0	0	37,493,123
Total Maintenance	320-323	590-598	DIST		56,983,181	0	0	56,983,181
Total Distribution Expense					$ 94,476,304	$ -	$ -	$ 94,476,304
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST		49,254,144	0	0	49,254,144
Customer Service and Information	320-323	906-907	DIST		574,640	0	0	574,640
Customer Assistance Expenses (Major only)	320-323	908	DIRECT		12,231,092	8,942,346	0	3,288,746
Customer Service and Information	320-323	909-910	DIST		1,491,260	0	0	1,491,260
Total Sales Expense	320-323	911-917	DIST		0	0	0	0
Total Customer and Sales Expenses					$ 63,551,136	$ 8,942,346	$ -	$ 54,608,789
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR		61,881,229	28,240,922	5,403,634	28,236,673
Office Supplies & Expenses	320-323	921	LABOR		4,604,979	2,101,588	402,119	2,101,272
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR		10,240,695	4,673,577	894,245	4,672,873
Outside Services Employed	320-323	923	LABOR		8,066,362	3,681,270	704,376	3,680,716
Property Insurance	320-323	924	PTDG		10,243,461	4,722,695	1,970,745	3,550,021
Injuries and Damages	320-323	925	LABOR		4,402,592	2,009,224	384,446	2,008,922
Employee Pensions & Benefits	320-323	926	LABOR		0	0	0	0
Franchise Requirements	320-323	927	DIST		0	0	0	0
Regulatory Commission Expenses	320-323	928	DIST		3,643,714	0	0	3,643,714
(Less) Duplicate Charges - Credit	320-323	929	PTDG		4,189,126	1,931,375	805,948	1,451,803
General Advertising Expenses	320-323	930.1	DIST		462,392	0	0	462,392
Miscellaneous General Expenses	320-323	930.2	DIST		13,489,709	0	0	13,489,709
Rents	320-323	931	DIST		3,585,754	0	0	3,585,754
Transportation Expenses (Non Major)	320-324	933	DIST		0	0	0	0
Maintenance								
Maintenance of General Plant	320-323	935	GPM		9,976,070	4,495,927	1,771,060	3,709,083
Total Administration and General Expenses					$ 105,926,442	$ 38,646,675	$ 8,936,187	$ 58,343,580

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended 8-4-2008

TABLE 20D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Total Operations and Maintenance					$ 1,122,913,388	$ 846,338,337	$ 67,988,422	$ 208,586,629
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST		393	0	0	393
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD	1,327,914	1,327,914	0	0
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST	18,156,583	9,078,682	3,425,989	5,651,912
Steam Production Plant	336	403	PROD		60,216,987	60,216,987	0	0
Nuclear Production Plant	336	403	PROD		0	0	0	0
Hydraulic Production Plant - Conventional	336	403	PROD		5,721,818	5,721,818	0	0
Hydraulic Production Plant - Pumped Storage	336	403	PROD		0	0	0	0
Other Production Plant	336	403	PROD		9,010,345	9,010,345	0	0
Transmission Plant (i)	336	403	TRANS		23,710,904	0	23,710,904	0
Distribution Plant	336	403	DIST		58,448,795	0	0	58,448,795
General Plant	336	403	GP		19,422,235	10,057,524	3,176,926	6,187,785
Common Plant - Electric	336	403	DIRECT		0	0	0	0
Common Plant - Electric	336	404	DIRECT		0	0	0	0
Depreciation Expense for Asset Retirement Costs	336	403	DIRECT	DIRECT	0	0	0	0
Amortization of Limited Term Electric Plant	336	404	DIRECT	DIRECT	3,216,847	0	0	3,216,847
Amortization of Plant Acquisition Adjustments (Electric)	200-201	114	DIRECT		2,365,780	2,365,780	0	0
Total Depreciation and Amortization					$ 201,598,600	$ 97,779,050	$ 30,313,819	$ 73,505,731
Total Operating Expenses					$ 1,324,511,988	$ 944,117,387	$ 98,302,241	$ 282,092,360
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Revised Amended 8-4-2008

TABLE 20E: Schedule 3A Items: Taxes (Including Income Taxes)

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Funct. Method	Total	Production	Transmission	Distribution/ Other
FEDERAL							
Income Tax (Included on Schedule 2)	262	409.1	DIST	$0	-	-	-
Employment Tax	262	408.1	LABOR	$14,392,279	6,568,248	1,256,772	6,567,259
Other Federal Taxes	262	408.1	DIST	$2,254,680	-	-	2,254,680
TOTAL FEDERAL				**$16,646,959**	**$ 6,568,248**	**$ 1,256,772**	**$ 8,821,939**
STATE AND OTHER							
Property	262	408.1	PTDG	$31,193,044	14,381,393	6,001,246	10,810,406
Unemployment	262	408.1	LABOR	$792,937	361,875	69,241	361,821
State Income, B&O, et.	262	409.1	DIST	$9,871,493	-	-	9,871,493
Franchise Fees	262	408.1	DIST	$8,857,115	-	-	8,857,115
Regulatory Commission	262	408.1	DIST	$3,178,053	-	-	3,178,053
City/Municipal	262	408.1	DIST	$1,352	-	-	1,352
Other	262	408.1	DIST	$4,591,196	-	-	4,591,196
TOTAL STATE AND OTHER TAXES				**$ 58,485,192**	**$ 14,743,268**	**$ 6,070,487**	**$ 37,671,437**
TOTAL TAXES				**$ 75,132,150**	**$ 21,311,516**	**$ 7,327,259**	**$ 46,493,376**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended 8-4-2008

TABLE 20F: Schedule 3B Other Included Items

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	DIST	-	-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST	-	-	-	-
Gain from Disposition of Utility Plant	114	411.6	DIRECT	DIST	-	-	-	-
(Less) Loss from Disposition of Utility Pla	114	411.7	DIRECT	DIST	-	-	-	-
Gain from Disposition of Allowances	114	411.8	PROD		6,561,302	6,561,302	-	-
(Less) Loss from Disposition of Allowanc	114	411.9	PROD		-	-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD	201,734,664	-	-	201,734,664
Total Other Included Items					**$ 208,295,965**	**$ 6,561,302**	**$ -**	**$ 201,734,664**
Sales for Resale:								
Sales for Resale	310	447	PROD		321,960,014	321,960,014	-	-
Total Sales for Resale					**$ 321,960,014**	**$ 321,960,014**	**$ -**	**$ -**
Other Revenues:								
Forfeited Discounts	300	450	DIST		2,975,481	-	-	2,975,481
Miscellaneous Service Revenues	300	451	DIST		2,053,231	-	-	2,053,231
Sales of Water and Water Power	300	453	PROD		6,575	6,575	-	-
Rent from Electric Property	300	454	TD		9,382,185	-	3,356,832	6,025,354
Interdepartmental Rents	300	455	DIST		-	-	-	-
Other Electric Revenues	300	456	DIRECT	PROD	32,597,273	-	2,917,644	29,679,629
Revenues from Transmission of Electricit	330	456.1	TRANS		15,250,210	-	15,250,210	-
Total Other Revenues					**$ 62,264,956**	**$ 6,575**	**$ 21,524,686**	**$ 40,733,696**
Total Other Included Items					**$ 592,520,936**	**$ 328,527,891**	**$ 21,524,686**	**$ 242,468,359**

(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	**PacifiCorp**	
End of Year Report Period:	**2006**	**Amended 7-8-2008**
ASC Filing Date:	**5/7/2008**	**Revised Amended 8-4-2008**

TABLE 20G: Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses	$ 1,324,511,988	$ 944,117,387	$ 98,302,241	$ 282,092,360
(From Schedule 3)				
Federal Income Tax Adjusted Return on Rate Base	$ 469,775,302	$ 205,264,593	$ 90,506,120	$ 174,004,589
(From Schedule 2)				
State and Other Taxes	$ 75,132,150	$ 21,311,516	$ 7,327,259	$ 46,493,376
(From Schedule 3a)				
Total Other Included Items	$ 592,520,936	$ 328,527,891	$ 21,524,686	$ 242,468,359
(From Schedule 3b)				
Total Cost	**$ 1,276,898,505**	**$ 842,165,605**	**$ 174,610,934**	**$ 260,121,966**

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	5/7/2008	Revised Amended 8-4-2008

TABLE 20G: Schedule 4: Average System Cost

Contract System Cost		
Production	$ 842,165,605	
Transmission	$ 174,610,934	
(Less) New Large Single Load Costs (d)	$ 16,964,577	49.59
Total Contract System Cost	**$ 999,811,962**	
Contract System Load (MWh)		
Total Retail Load	21,409,637	
(Less) New Large Single Load	342,068	
Total Retail Load (Net of NLSL) (d)	21,067,569	
Distribution Loss (f)	573,778	2.680%
Total Contract System Load	**21,641,347**	
Average System Cost $/MWh	**46.20**	

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 20H: Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	91,257
Transmission	354-355	8,219,113
Distribution	354-355	44,923,847
Customer Accounts	354-355	44,819,490
Customer Service and Information	354-355	4,813,730
Sales	354-355	
Administrative and General	354-355	87,938,267
TOTAL Operation		**$190,805,704**
Maintenance		
Production	354-355	44,010,267
Transmission	354-355	8,186,844
Distribution	354-355	55,388,388
Administrative and General	354-355	2,634,400
TOTAL Maintenance		**$110,219,899**
Operation and Maintenance		
Production (Enter Total of lines 1 and 9)	354-355	135,267,819
Transmission (Enter Total of lines 2 and 10)	354-355	16,405,957
Distribution (Enter Total of lines 3 and 11)	354-355	100,312,235
Customer Accounts (Transcribe from line 4)	354-355	44,819,490
Customer Service and Information (Transcribe from line 5)	354-355	4,813,730
Sales (Transcribe from line 6)	354-355	0
Administrative and General (Enter Total of lines 7 and 12)	354-355	90,572,667
TOTAL Operation and Maintenance		**$392,191,898**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

***TABLE 20I:* Ratio Table**

Labor Ratio Input:		Ratio Used	Total	Production	Transmission	Distribution
	Production	PROD	$ 135,267,819	$ 135,267,819	$ -	$ -
	Transmission	TRANS	16,405,957	-	16,405,957	-
	Distribution	DIST	100,312,235	-	-	100,312,235
	Customer Accounts	DIST	44,819,490	-	-	44,819,490
	Customer Service and Informational	DIRECT	4,813,730	3,010,846	-	1,802,884
	Sales	DIST	-	-	-	-
	Administrative & General	PTD	90,572,667	40,707,129	17,841,283	32,024,255
Total Labor			$ 392,191,898	$ 178,985,794	$ 34,247,240	$ 178,958,864
	Labor Ratio		**100%**	**46%**	**9%**	**46%**

GP	General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Land and Land Rights	PTD	$ 6,170,540	$ 2,773,298	$ 1,215,492	$ 2,181,750
	Structures and Improvements	PTD	105,236,114	47,297,493	20,729,734	37,208,887
	Furniture and Equipment	LABOR	46,835,393	21,374,409	4,089,791	21,371,193
	Transportation Equipment	TD	40,859,704	-	14,619,105	26,240,599
	Stores Equipment	PTD	5,341,312	2,400,608	1,052,148	1,888,556
	Tools and Garage Equipment	PTD	26,417,572	11,873,157	5,203,815	9,340,600
	Laboratory Equipment	PTD	17,955,617	8,070,002	3,536,953	6,348,662
	Power Operated Equipment	TD	54,030,242	-	19,331,363	34,698,878
	Communication Equipment	PTD	109,518,404	49,222,132	21,573,272	38,722,999
	Miscellaneous Equipment	PTD	2,440,871	1,097,029	480,810	863,032
	Other Tangible Property	DIRECT	146,618,604	146,618,604	-	-
	Asset Retirement Costs for General Plant	PTD	17,834	8,015	3,513	6,306
	TOTAL		$ 561,442,204	$ 290,734,747	$ 91,835,996	$ 178,871,461
	RATIO (GP)		**100%**	**52%**	**16%**	**32%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 20I: Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
PTD	**Production, Transmission, Distribution Ratio**					
	Steam Production	PROD	$ 2,066,689,427	$ 2,066,689,427	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	233,341,208	233,341,208	-	-
	Other Production	PROD	348,799,787	348,799,787	-	-
	Total Production Plant		2,648,830,422	2,648,830,422	-	-
	Transmission Plant	TRANS	1,160,939,950	-	1,160,939,950	-
	Total Distribution Plant	DIST	2,083,832,056	-	-	2,083,832,056
	TOTAL		$ 5,893,602,429	$ 2,648,830,422	$ 1,160,939,950	$ 2,083,832,056
	PTD Ratio		**100%**	**45%**	**20%**	**35%**

		Ratio Used	Total	Production	Transmission	Distribution
PTDG	**Production, Transmission, Distribution and General Plant Ratio**					
	PTD Total		$ 5,893,602,429	$ 2,648,830,422	$ 1,160,939,950	$ 2,083,832,056
	Intangible Plant - Organization	DIST	-	-	-	-
	Intangible Plant - Franchises and Consents	DIRECT	51,880,743	50,880,743	-	1,000,000
	Intangible Plant - Miscellaneous	DIRECT	244,725,490	122,368,003	46,177,570	76,179,916
	General Plant Total		561,442,204	290,734,747	91,835,996	178,871,461
	TOTAL		$ 6,751,650,866	$ 3,112,813,916	$ 1,298,953,516	$ 2,339,883,434
	PTDG RATIO		**100%**	**46%**	**19%**	**35%**

		Ratio Used	Total	Production	Transmission	Distribution
TD	**Transmission and Distribution Plant Ratio**					
	Total Transmission Plant	TRANS	$ 1,160,939,950	$ -	$ 1,160,939,950	$ -
	Total Distribution Plant	DIST	2,083,832,056	-	-	2,083,832,056
	TOTAL		$ 3,244,772,006	$ -	$ 1,160,939,950	$ 2,083,832,056
	TD RATIO		**100%**	**0%**	**36%**	**64%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

TABLE 20I: Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
GPM	**Maintenance of General Plant Ratio**					
	Structures and Improvements	PTD	$ 105,236,114	$ 47,297,493	$ 20,729,734	$ 37,208,887
	Furniture and Equipment	LABOR	46,835,393	21,374,409	4,089,791	21,371,193
	Communication Equipment	PTD	109,518,404	49,222,132	21,573,272	38,722,999
	Miscellaneous Equipment	PTD	2,440,871	1,097,029	480,810	863,032
	TOTAL		$ 264,030,781	$ 118,991,063	$ 46,873,607	$ 98,166,111
	GPM RATIO		100%	45%	18%	37%

SUMMARY RATIO TABLE

Conservation Functionalization	CONS	70.00%	0.00%	30.00%
Direct to Distribution	DIST	0.00%	0.00%	100.00%
Direct to Production	PROD	100.00%	0.00%	0.00%
Direct to Transmission	TRANS	0.00%	100.00%	0.00%
Direct Allocation	DIRECT	0.00%	0.00%	0.00%
General Plant	GP	51.78%	16.36%	31.86%
Maintenance of General Plant	GPM	45.07%	17.75%	37.18%
Labor Ratios	LABOR	45.64%	8.73%	45.63%
Production, Transmission, Distribution	PTD	44.94%	19.70%	35.36%
Production, Transmission, Distribution, General	PTDG	46.10%	19.24%	34.66%
Transmission, Distribution	TD	0.00%	35.78%	64.22%

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

TABLE 20J

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	PacifiCorp
End of Year Report Period:	2006
ASC Filing Date:	5/7/2008

Purchased Power & Off-System Sales

FERC Form 1		Purchased Power	
Statistical Classification	Page Number	Settlement Total	MWh Purchased
RQ	326-327	$ -	0
LF	326-327	$ 96,519,574	2,165,429
IF	326-327	$ 27,850,040	506,935
SF	326-327	$ 650,493,861	12,175,675
LU	326-327	$ 107,918,926	2,489,865
IU	326-327	$ 18,313,015	235,818
OS	326-327	$ 25,573,047	565,338
EX	326-327	$ 10,238,900	0
NA	326-327	$ 5,552,110	2,681
AD	326-327	$ (590,283,665)	(11,297,586)
TOTAL		**$ 352,175,806**	**6,844,154**

FERC Form 1		Sales for Resale	
Statistical Classification	Page Number	Settlement Total	MWh Sold
RQ	310-311	$ 3,318,147	92,625
LF	310-311	$ 95,070,260	2,046,544
IF	310-311	$ 5,518,297	131,696
SF	310-311	$ 201,204,058	3,400,733
LU	310-311	$ 11,668,614	271,771
IU	310-311	$ 285,274	7,507
OS	310-311	$ (2,384,964)	(43,146)
EX	310-311	$ -	0
NA	310-311	$ 7,283,944	(52,537)
AD	310-311	$ (3,616)	222
TOTAL		**$ 321,960,014**	**5,855,415**

PAC **TABLE 20K: Forecasted Contract System Costs & ASC with New Additions and NLSL**

Date	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
	10	11	12	13	14
Fiscal Year	2009	2010	2011	2012	2013
Rate Period Mid-Point	**TRUE**	**FALSE**	**FALSE**	**FALSE**	**FALSE**
Contract System Cost					
Production	1,001,429,090	964,635,860	972,845,032	973,829,991	977,745,929
Transmission	172,107,523	170,231,271	168,517,142	166,841,503	165,247,996
NLSL Fully Allocated Cost ($/MWh)	58.07	55.78	55.70	55.18	54.74
(Less) New Large Single Load Costs (d)	**19,865,032**	**19,078,938**	**19,052,436**	**18,876,147**	**18,726,097**
Total Contract System Cost	1,153,671,581	1,115,788,194	1,122,309,738	1,121,795,347	1,124,267,828
Contract System Load (MWh)					
Total Retail Load @ Meter	22,016,008	22,207,898	22,427,330	22,654,332	22,880,278
(Less) New Large Single Load	**342,068**	**342,068**	**342,068**	**342,068**	**342,068**
Total Retail Load (Net of NLSL) (d)	21,673,940	21,865,830	22,085,262	22,312,264	22,538,210
Distribution Loss (f)	590,029	595,172	601,052	607,136	613,191
Total Contract System Load	22,263,969	22,461,002	22,686,314	22,919,400	23,151,401
Average System Cost $/MWh	**51.82**	**49.68**	**49.47**	**48.95**	**48.56**

	Rate Period Mid-Point	New Resources											
			(0.06)	**0.93**	**(0.10)**	**1.38**	**(0.11)**	**0.41**	**(0.08)**	**1.02**	**(0.09)**	**0.58**	**(0.09)**
Date	**4/1/09**	**4/1/2009**	**4/1/2009**	**4/1/2009**	**4/1/2009**	**4/1/2009**	**4/1/2009**	**4/1/2009**	**4/1/2009**	**4/1/2009**	**4/1/2009**	**4/1/2009**	**4/1/2009**
Fiscal Year	2009	2009	2009	2009	2009	2009	2009	2009	2009	2009	2009	2009	2009
NLSL Switch	1	0	1	0	1	0	1	0	1	0	1	0	1
Contract System Cost													
Production	1,001,429,090	914,712,077	914,712,077	934,149,781	934,149,781	962,793,816	962,793,816	969,459,697	969,459,697	990,510,661	990,510,661	1,001,429,090	1,001,429,090
Transmission	172,107,523	171,497,847	171,497,847	171,577,112	171,577,112	171,774,118	171,774,118	171,839,981	171,839,981	172,029,459	172,029,459	172,107,523	172,107,523
(Less) New Large Single Load Costs (d)	19,865,032	**0**	**17,875,233**	**0**	**18,971,050**	**0**	**19,685,533**	**0**	**19,111,855**	**0**	**19,597,038**	**0**	**19,865,032**
Total Contract System Cost	1,153,671,581	1,086,209,924	1,068,334,691	1,105,726,893	1,086,755,843	1,134,567,933	1,114,882,401	1,141,299,679	1,122,187,823	1,162,540,120	1,142,943,081	1,173,536,614	1,153,671,581
Contract System Load (MWh)													
Total Retail Load @ Meter	22,016,008	22,016,008	22,016,008	22,016,008	22,016,008	22,016,008	22,016,008	22,016,008	22,016,008	22,016,008	22,016,008	22,016,008	22,016,008
(Less) New Large Single Load	**342,068**	**0**	**342,068**	**0**	**342,068**	**0**	**342,068**	**0**	**342,068**	**0**	**342,068**	**0**	**342,068**
Total Retail Load (Net of NLSL) (d)	21,673,940	22,016,008	21,673,940	22,016,008	21,673,940	22,016,008	21,673,940	22,016,008	21,673,940	22,016,008	21,673,940	22,016,008	21,673,940
Distribution Loss (f)	590,029	590,029	590,029	590,029	590,029	590,029	590,029	590,029	590,029	590,029	590,029	590,029	590,029
Total Contract System Load	22,263,969	22,606,037	22,263,969	22,606,037	22,263,969	22,606,037	22,263,969	22,606,037	22,263,969	22,606,037	22,263,969	22,606,037	22,263,969
Average System Cost $/MWh	**51.82**	**48.05**	**47.98**	**48.91**	**48.81**	**50.19**	**50.08**	**50.49**	**50.40**	**51.43**	**51.34**	**51.91**	**51.82**
					$ 0.83		**$ 1.26**		**$ 0.33**		**$ 0.93**		**$ 0.48**

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Tables for:

Portland General Electric

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Portland General Electric	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2006	Revised Amended BPA: 8-4-2008

TABLE 21A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST		-	-	-	-
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD	48,460,534	48,460,534	-	-
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST	123,314,826	2,904,530	7,417,801	112,992,495
Total Intangible Plant					$ 171,775,360	$ 51,365,064	$ 7,417,801	$ 112,992,495
Production Plant:								
Steam Production	204-207	310-316	PROD		819,407,522	819,407,522	-	-
Nuclear Production	204-207	320-325	PROD		0	-	-	-
Hydraulic Production	204-207	330-336	PROD		237,821,189	237,821,189	-	-
Other Production	204-207	340-346	PROD		356,882,306	356,882,306	-	-
Total Production Plant					$ 1,414,111,017	$ 1,414,111,017	$ -	$ -
Transmission Plant: (i)								
Transmission Plant	204-207	350-359	TRANS		283,206,605	-	283,206,605	-
Total Transmission Plant					$ 283,206,605	$ -	$ 283,206,605	$ -
Distribution Plant:								
Distribution Plant	204-207	360-373	DIST		2,058,570,452	-	-	2,058,570,452
Total Distribution Plant					$ 2,058,570,452	$ -	$ -	$ 2,058,570,452
General Plant:								
Land and Land Rights	204-207	389	PTD		4,635,830	1,745,414	349,557	2,540,859
Structures and Improvements	204-207	390	PTD		56,435,602	21,248,292	4,255,434	30,931,876
Furniture and Equipment	204-207	391	LABOR		36,822,574	11,448,061	1,928,782	23,445,731
Transportation Equipment	204-207	392	TD		34,739,628	-	4,201,293	30,538,335
Stores Equipment	204-207	393	PTD		756,653	284,884	57,054	414,715
Tools and Garage Equipment	204-207	394	PTD		10,208,409	3,843,518	769,748	5,595,143
Laboratory Equipment	204-207	395	PTD		10,320,839	3,885,849	778,226	5,656,764
Power Operated Equipment	204-207	396	TD		34,686,429	-	4,194,860	30,491,569
Communication Equipment	204-207	397	PTD		53,261,072	20,053,065	4,016,064	29,191,943
Miscellaneous Equipment	204-207	398	PTD		267,571	100,742	20,176	146,653
Other Tangible Property	204-207	399	PTD	PTD	0	-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD		55,510	20,900	4,186	30,425
Total General Plant					$ 242,190,117	$ 62,630,724	$ 20,575,380	$ 158,984,013

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Portland General Electric	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2006	Revised Amended BPA: 8-4-2008

TABLE 21A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Total Electric Plant In-Service					$ 4,169,853,551	$ 1,528,106,805	$ 311,199,786	$ 2,330,546,960
(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)								
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD		550,562,907	550,562,907	-	-
Nuclear Production Plant	219	108	PROD		0	-	-	-
Hydraulic Production Plant	219	108	PROD		132,555,670	132,555,670	-	-
Other Production Plant	219	108	PROD		194,759,215	194,759,215	-	-
Transmission Plant (i)	219	108	TRANS		138,611,020	-	138,611,020	-
Distribution Plant	219	108	DIST		1,071,604,888	-	-	1,071,604,888
General Plant	219	108	GP		105,121,755	27,184,642	8,930,670	69,006,443
Amortization of Intangible Plant - Account 301	219	111	DIST			-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD	1,897,268	1,897,268	-	-
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST	79,891,017	1,881,735	4,805,713	73,203,569
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	111	DIST			-	-	-
Capital Lease - Common Plant	219	108	DIRECT			-	-	-
Leasehold Improvements	200-201	108	DIST	DIST		-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT			-	-	-
Amortization of Other Utility Plant (a)	200-201	108	DIST	DIST		-	-	-
Amortization of Acquisition Adjustments	200-201	115	DIRECT			-	-	-
Depreciation and Amortization Reserve (Other)			DIRECT	DIRECT				
Total Depreciation and Amortization Reserve					$ 2,275,003,740	$ 908,841,437	$ 152,347,403	$ 1,213,814,899
Total Net Plant					$ 1,894,849,811	$ 619,265,368	$ 158,852,383	$ 1,116,732,060
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME: **Portland General Electric**
End of Year Report Period: **2006** — Amended BPA: 7-8-2008
ASC Filing Date: **5/7/2006** — Revised Amended BPA: 8-4-2008

TABLE 21A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation: Automatic Input from Sch 1A				46,175,221	11,395,265	10,200,607	24,579,349
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST		187,790	-	-	187,790
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD		0	-	-	-
Nuclear Fuel		120.1-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST		412,182,006	-	-	412,182,006
Common Plant	356 & 356.1		DIRECT					
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST		-	-	-
Total					**$ 412,369,796**	**$ -**	**$ -**	**$ 412,369,796**
Other Property and Investments								
Investment in Associated Companies	110-111	123	DIST	DIST	53,882	-	-	53,882
Other Investment	110-111	124	DIST		203,017	-	-	203,017
Long-Term Portion of Derivative Assets	110-111	175	DIST		0	-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST		0	-	-	-
Total					**$ 256,899**	**$ -**	**$ -**	**$ 256,899**
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD		32,581,087	32,581,087	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD		0	-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD		27,957,550	10,526,160	2,108,093	15,323,296
Merchandise (Major Only)	110-112	155	DIST		0	-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST		45,111	-	-	45,111
EPA Allowance Inventory	110-112	158.1	PROD		360,000	360,000	-	-
EPA Allowances Withheld	110-112	158.2	PROD			-	-	-
Stores Expense Undistributed	110-111	163	PTD		3,127,811	1,177,637	235,847	1,714,327
Prepayments	110-111	165	PTD		24,581,506	9,255,062	1,853,528	13,472,915
Derivative Instrument Assets	110-111	175	DIST		72,874,522	-	-	72,874,522
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST		0	-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST		19,703,359	-	-	19,703,359
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST		0	-	-	-
Total					**$ 181,230,946**	**$ 53,899,946**	**$ 4,197,469**	**$ 123,133,530**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Portland General Electric	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2006	Revised Amended BPA: 8-4-2008

TABLE 21A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG		15,252,228	5,589,413	1,138,287	8,524,528
Extraordinary Property Losses	110-111	182.1	DIST	DIST	0	-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIST	DIST	65,666,225	-	-	65,666,225
Other Regulatory Assets	110-111	182.3	DIRECT	DIST	280,324,211	43,988,681	5,924,586	230,410,944
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST		17,989	-	-	17,989
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST		0	-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST		0	-	-	-
Clearing Accounts	110-111	184	DIST		(126)	-	-	(126)
Temporary Facilities	110-111	185	PTDG		0	-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST	18,117,621	8,160,874	1,787,168	8,169,579
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT	DIRECT	0			
Research, Development, and Demonstration Expenditures	110-111	188	DIST		0	-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG		30,475,465	11,168,202	2,274,410	17,032,853
Accumulated Deferred Income Taxes	110-111	190	DIST		254,935,884	-	-	254,935,884
Total					**$ 664,789,497**	**$ 68,907,170**	**$ 11,124,452**	**$ 584,757,876**
Total Assets and Other Debits					**$ 1,304,822,359**	**$ 134,202,381**	**$ 25,522,527**	**$ 1,145,097,451**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Portland General Electric	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2006	Revised Amended BPA: 8-4-2008

TABLE 21A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Liabilities and Other Credits (Comparative Balance Sheet)								
CURRENT AND ACCRUED LIABILITIES								
Derivative Instrument Liabilities	112-113	244	DIST		139,838,646	-	-	139,838,646
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST		0	-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST		15,067,825	-	-	15,067,825
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST		0	-	-	-
Total					**$ 154,906,471**	**$ -**	**$ -**	**$ 154,906,471**
DEFERRED CREDITS								
Customer Advances for Construction	112-113	252	DIST		77,123	-	-	77,123
Other Deferred Credits	112-113	253	DIRECT	DIST	32,739,457	9,952,177	1,681,348	21,105,932
Other Regulatory Liabilities	112-113	254	DIRECT	DIST	87,826,316	18,403,173	2,019,715	67,403,427
Accumulated Deferred Investment Tax Credits	112-113	255	DIST		6,872,117	-	-	6,872,117
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT	DIRECT	0			
Unamortized Gain on Reacquired Debt	112-113	257	PTDG		244,184	89,485	18,224	136,475
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST		0	-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST		273,176,670	-	-	273,176,670
Accumulated Deferred Income Taxes-Other	112-113	283	DIST		210,311,503	-	-	210,311,503
Total					**$ 611,247,370**	**$ 28,444,836**	**$ 3,719,287**	**$ 579,083,248**
Total Liabilities and Other Credits					**$ 766,153,841**	**$ 28,444,836**	**$ 3,719,287**	**$ 733,989,719**
Total Rate Base					**$ 2,433,518,329**	**$ 725,022,913**	**$ 180,655,623**	**$ 1,527,839,792**

(Total Net Plant + Debits - Credits)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric
End of Year Report Period:	2006
ASC Filing Date:	5/7/2006

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 21B: Schedule 1A: Cash Working Capital (f)

(Automatic Input from Schedule 3- Expenses)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	1,316,964,069	1,314,965,424	-	1,998,645
Total Transmission O&M (i)	76,820,098	-	76,820,098	-
Total Distribution O&M	63,378,119	-	-	63,378,119
Total Customer & Sales	61,844,133	-	-	61,844,133
Total Administrative and General O&M	104,301,298	28,103,999	4,784,755	71,412,544
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	1,253,905,949	1,251,907,304	-	1,998,645
Revised Total O&M Expenses	**$ 369,401,768**	**$ 91,162,119**	**$ 81,604,853**	**$ 196,634,796**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 46,175,221**	**$ 11,395,265**	**$ 10,200,607**	**$ 24,579,349**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric	Amended BPA: 7-8-2008
End of Year Report Period:	2006	Revised Amended BPA: 8-4-2008
ASC Filing Date:	5/7/2006	

TABLE 21C: Schedule 2: Capital Structure and Rate of Return (b)

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:	11.009%
Multi-Jurisdiction Investor-Owned Utility Return Calculation:	
Consumer-Owned Utility Return Calculation:	
Rate of Return :	**11.009%**

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order

Note: Multi-jurisdictional utilities must begin on Page 2

Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**
Debt	$ 900,000.0	50.0%	6.48%	3.240%
Preferred Equity	$ -			
Common Equity	$ 900,000.0	50.0%	10.10%	5.050%
Weighted Cost of Capital	**$ 1,800,000.0**	**100.000%**		**8.290%**

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	**35%**
Federal Income Tax Factor	2.719%

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital 11.009%

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 2,433,518,329	$ 725,022,913	$ 180,655,623	$ 1,527,839,792
Federal Income Tax Adjusted Weighted Cost of Capital	11.009%	11.009%	11.009%	11.009%
Federal Income Tax Adjusted Return on Rate Base	**$267,911,649**	**$79,819,446**	**$19,888,794**	**$168,203,409**

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2006	Revised Amended BPA: 8-4-2008

TABLE 21D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD		42,832,603	42,832,603	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD		8,742,850	8,742,850	-	-
Steam Power - Maintenance	320-323	510-515	PROD		20,194,844	20,194,844	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD		0	-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD		0	-	-	-
Nuclear - Maintenance	320-323	528-532	PROD		0	-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD		5,008,688	5,008,688	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD		3,963,730	3,963,730	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD		60,659,664	60,659,664	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD		6,935,728	6,935,728	-	-
Other Power - Maintenance	320-323	551-554.1	PROD		6,489,996	6,489,996	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	320-323	555	PROD		1,110,440,782	1,110,440,782	-	-
System Control and Load Dispatching	320-323	556	PROD		2,807,073	2,807,073	-	-
Other Expenses	320-323	557	PROD		8,915,211	8,915,211	-	-
BPA REP Reversal	327	555	PROD		0	-	-	-
Public Purpose Charges (h)			DIRECT		39,972,900	37,974,255	-	1,998,645
Total Production Expense					**$ 1,316,964,069**	**$ 1,314,965,424**	**$ -**	**$ 1,998,645**
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS		65,426,297	-	65,426,297	-
Total Operations less Wheeling	320-323	560-567.1	TRANS		7,741,552	-	7,741,552	-
Total Maintenance	320-323	568-574	TRANS		3,652,249	-	3,652,249	-
Total Transmission Expense					**$ 76,820,098**	**$ -**	**$ 76,820,098**	**$ -**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2006	Revised Amended BPA: 8-4-2008

TABLE 21D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Distribution Expense:								
Total Operations	320-323	580-589	DIST		16,812,695	-	-	16,812,695
Total Maintenance	320-323	590-598	DIST		46,565,424	-	-	46,565,424
Total Distribution Expense					$ 63,378,119	$ -	$ -	$ 63,378,119
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST		53,203,505	-	-	53,203,505
Customer Service and Information	320-323	906-907	DIST		0	-	-	-
Customer Assistance Expenses (Major only)	320-323	908	DIRECT		5,961,194			5,961,194
Customer Service and Information	320-323	909-910	DIST		2,678,858	-	-	2,678,858
Total Sales Expense	320-323	911-917	DIST		576	-	-	576
Total Customer and Sales Expenses					$ 61,844,133	$ -	$ -	$ 61,844,133
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR		35,306,793	10,976,808	1,849,385	22,480,600
Office Supplies & Expenses	320-323	921	LABOR		17,177,243	5,340,369	899,751	10,937,123
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR		11,527,949	3,584,015	603,839	7,340,095
Outside Services Employed	320-323	923	LABOR		5,219,349	1,622,685	273,392	3,323,273
Property Insurance	320-323	924	PTDG		4,187,987	1,534,752	312,553	2,340,682
Injuries and Damages	320-323	925	LABOR		2,660,644	827,189	139,366	1,694,090
Employee Pensions & Benefits	320-323	926	LABOR		36,359,490	11,304,089	1,904,525	23,150,875
Franchise Requirements	320-323	927	DIST		0	-	-	-
Regulatory Commission Expenses	320-323	928	DIST		6,075,669	-	-	6,075,669
(Less) Duplicate Charges - Credit	320-323	929	PTDG		1,661,537	608,896	124,002	928,639
General Advertising Expenses	320-323	930.1	DIST		1,188,047	-	-	1,188,047
Miscellaneous General Expenses	320-323	930.2	DIST		3,490,273	-	-	3,490,273
Rents	320-323	931	DIST		3,902,378	-	-	3,902,378
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM		1,922,911	691,019	133,624	1,098,268
Total Administration and General Expenses					$ 104,301,298	$ 28,103,999	$ 4,784,755	$ 71,412,544

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric
End of Year Report Period:	2006
ASC Filing Date:	5/7/2006

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 21D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Total Operations and Maintenance					$ 1,623,307,717	$ 1,343,069,423	$ 81,604,853	$ 198,633,441
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD	1,107,986	1,107,986	-	-
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST	13,896,085	327,305	835,896	12,732,884
Steam Production Plant	336	403	PROD		20,721,649	20,721,649	-	-
Nuclear Production Plant	336	403	PROD		0	-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD		5,958,311	5,958,311	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD		0	-	-	-
Other Production Plant	336	403	PROD		13,687,735	13,687,735	-	-
Transmission Plant (i)	336	403	TRANS		7,174,396	-	7,174,396	-
Distribution Plant	336	403	DIST		102,478,860	-	-	102,478,860
General Plant	336	403	GP		12,388,386	3,203,655	1,052,461	8,132,270
Common Plant - Electric	336	403	DIRECT		0			
Common Plant - Electric	336	404	DIRECT					
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT		31,571	18,563	655	12,353
Amortization of Limited Term Electric Plant	336	404	DIRECT					
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIRECT		0			
Total Depreciation and Amortization					$ 177,444,979	$ 45,025,204	$ 9,063,409	$ 123,356,366
Total Operating Expenses					$ 1,800,752,696	$ 1,388,094,627	$ 90,668,261	$ 321,989,807
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric
End of Year Report Period:	2006
ASC Filing Date:	5/7/2006

Amended BPA: 7-8-2008

Revised Amended BPA: 8-4-2008

TABLE 21E: Schedule 3A Items: Taxes (Including Income Taxes)

Account Description	FERC Form 1		Funct. Method	Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers					
FEDERAL							
Income Tax (Included on Schedule 2)	262	409.1	DIST	101,754,808	-	-	101,754,808
Employment Tax	262	408.1	LABOR	14,902,734	4,633,229	780,611	9,488,894
Other Federal Taxes	262	408.1	DIST	1,053,015	-	-	1,053,015
TOTAL FEDERAL				**$ 117,710,557**	**$ 4,633,229**	**$ 780,611**	**$ 112,296,717**
STATE AND OTHER							
Property	262	408.1	PTDG	33,141,089	12,145,060	2,473,348	18,522,680
Unemployment	262	408.1	LABOR	1,453,141	451,778	76,116	925,246
State Income, B&O, et.	262	409.1	DIST	2,523,049	-	-	2,523,049
Franchise Fees	262	408.1	DIST	32,275,220	-	-	32,275,220
Regulatory Commission	262	408.1	DIST	4,982,054	-	-	4,982,054
City/Municipal	262	408.1	DIST	0	-	-	-
Other	262	408.1	DIST	(1,424,168)	-	-	(1,424,168)
TOTAL STATE AND OTHER TAXES				**$ 72,950,385**	**$ 12,596,839**	**$ 2,549,464**	**$ 57,804,082**
TOTAL TAXES				**$ 190,660,942**	**$ 17,230,068**	**$ 3,330,076**	**$ 170,100,798**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2006	Revised Amended BPA: 8-4-2008

TABLE 21F: Schedule 3B Other Included Items

Account Description	FERC Form 1		Functionalization Method					
	Page Number	Account Numbers	Default	Optional	Total	Production	Transmission	Distribution/ Other
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD	5,452,016	5,452,016	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST	32,035,974	-	-	32,035,974
Gain from Disposition of Utility Plant	114	411.6	DIRECT	PROD	293,588	293,588	-	-
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST	-	-	-	-
Gain from Disposition of Allowances	114	411.8	PROD		-	-	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD		-	-	-	-
Miscellaneous Nonoperating Income	114	421	PROD	PROD	6,202,968	6,202,968	-	-
Total Other Included Items					**$ (20,087,402)**	**$ 11,948,572**	**$ -**	**$ (32,035,974)**
Sales for Resale:								
Sales for Resale	310	447	PROD		650,409,850	650,409,850	-	-
Total Sales for Resale					**$ 650,409,850**	**$ 650,409,850**	**$ -**	**$ -**
Other Revenues:								
Forfeited Discounts	300	450	DIST		625,520	-	-	625,520
Miscellaneous Service Revenues	300	451	DIST		1,393,724	-	-	1,393,724
Sales of Water and Water Power	300	453	PROD		(46,202)	(46,202)	-	-
Rent from Electric Property	300	454	TD		6,434,441	-	778,160	5,656,281
Interdepartmental Rents	300	455	DIST		-	-	-	-
Other Electric Revenues	300	456	PROD	PROD	42,553,031	42,553,031	-	-
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS		4,350,543	-	4,350,543	-
Total Other Revenues					**$ 55,311,057**	**$ 42,506,829**	**$ 5,128,703**	**$ 7,675,525**
Total Other Included Items					**$ 685,633,505**	**$ 704,865,251**	**$ 5,128,703**	**$ (24,360,449)**

(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2006	Revised Amended BPA: 8-4-2008

TABLE 21G: Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses	$ 1,800,752,696	$ 1,388,094,627	$ 90,668,261	$ 321,989,807
(From Schedule 3)				
Federal Income Tax Adjusted Return on Rate Base	$ 267,911,649	$ 79,819,446	$ 19,888,794	$ 168,203,409
(From Schedule 2)				
State and Other Taxes	$ 190,660,942	$ 17,230,068	$ 3,330,076	$ 170,100,798
(From Schedule 3a)				
Total Other Included Items	$ 685,633,505	$ 704,865,251	$ 5,128,703	$ (24,360,449)
(From Schedule 3b)				
Total Cost	**$ 1,573,691,782**	**$ 780,278,890**	**$ 108,758,429**	**$ 684,654,463**

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2006	Revised Amended BPA: 8-4-2008

TABLE 21G: Schedule 4: Average System Cost

Contract System Cost	
Production	$ 780,278,890
Transmission	$ 108,758,429
(Less) New Large Single Load Costs (d)	$ 15,957,669
Total Contract System Cost	**$ 873,079,649**
Contract System Load (MWh)	
Total Retail Load	18,432,527
(Less) New Large Single Load	328,992
Total Retail Load (Net of NLSL) (d)	18,103,535
Distribution Loss (f) (See Distribution Loss Schedule)	868,172
Total Contract System Load	**18,971,707**
Average System Cost $/MWh	**46.02**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME: Portland General Electric
End of Year Report Period: 2006
ASC Filing Date: 5/7/2006
Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 21H: Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	19,297,986
Transmission	354-355	3,285,157
Distribution	354-355	13,836,501
Customer Accounts	354-355	27,537,974
Customer Service and Information	354-355	3,238,402
Sales	354-355	387
Administrative and General	354-355	32,699,999
TOTAL Operation		**$99,896,406**
Maintenance		
Production	354-355	7,751,800
Transmission	354-355	870,747
Distribution	354-355	18,264,548
Administrative and General	354-355	841,715
TOTAL Maintenance		**$27,728,810**
Operation and Maintenance		
Production (Enter Total of lines 1 and 9)	354-355	27,049,786
Transmission (Enter Total of lines 2 and 10)	354-355	4,155,904
Distribution (Enter Total of lines 3 and 11)	354-355	32,101,049
Customer Accounts (Transcribe from line 4)	354-355	27,537,974
Customer Service and Information (Transcribe from line 5)	354-355	3,238,402
Sales (Transcribe from line 6)	354-355	387
Administrative and General (Enter Total of lines 7 and 12)	354-355	33,541,714
TOTAL Operation and Maintenance		**$127,625,216**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric
End of Year Report Period:	2006
ASC Filing Date:	5/7/2006

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 21I: Ratio Table

Labor Ratio Input:	Ratio Used	Total	Production	Transmission	Distribution
Production	PROD	$ 27,049,786	$ 27,049,786	$ -	$ -
Transmission	TRANS	4,155,904	-	4,155,904	-
Distribution	DIST	32,101,049	-	-	32,101,049
Customer Accounts	DIST	27,537,974	-	-	27,537,974
Customer Service and Informational	DIRECT	3,238,402	-	-	3,238,402
Sales	DIST	387	-	-	387
Administrative & General	PTD	33,541,714	12,628,626	2,529,158	18,383,929
Total Labor		$ 127,625,216	$ 39,678,412	$ 6,685,062	$ 81,261,741
Labor Ratio		**100%**	**31.09%**	**5.24%**	**63.67%**

GP General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
Land and Land Rights	PTD	$ 4,635,830	$ 1,745,414	$ 349,557	$ 2,540,859
Structures and Improvements	PTD	56,435,602	21,248,292	4,255,434	30,931,876
Furniture and Equipment	LABOR	36,822,574	11,448,061	1,928,782	23,445,731
Transportation Equipment	TD	34,739,628	-	4,201,293	30,538,335
Stores Equipment	PTD	756,653	284,884	57,054	414,715
Tools and Garage Equipment	PTD	10,208,409	3,843,518	769,748	5,595,143
Laboratory Equipment	PTD	10,320,839	3,885,849	778,226	5,656,764
Power Operated Equipment	TD	34,686,429	-	4,194,860	30,491,569
Communication Equipment	PTD	53,261,072	20,053,065	4,016,064	29,191,943
Miscellaneous Equipment	PTD	267,571	100,742	20,176	146,653
Other Tangible Property	DIRECT	-	-	-	-
Asset Retirement Costs for General Plant	PTD	55,510	20,900	4,186	30,425
TOTAL		$ 242,190,117	$ 62,630,724	$ 20,575,380	$ 158,984,013
RATIO (GP)		**100%**	**25.86%**	**8.50%**	**65.64%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric
End of Year Report Period:	2006
ASC Filing Date:	5/7/2006

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 21I: Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
PTD	**Production, Transmission, Distribution Ratio**	**Ratio Used**	**Total**	**Production**	**Transmission**	**Distribution**
	Steam Production	PROD	$ 819,407,522	$ 819,407,522	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	237,821,189	237,821,189	-	-
	Other Production	PROD	356,882,306	356,882,306	-	-
	Total Production Plant		1,414,111,017	1,414,111,017	-	-
	Transmission Plant	TRANS	283,206,605	-	283,206,605	-
	Total Distribution Plant	DIST	2,058,570,452	-	-	2,058,570,452
	TOTAL		$ 3,755,888,074	$ 1,414,111,017	$ 283,206,605	$ 2,058,570,452
	PTD Ratio		**100%**	**37.65%**	**7.54%**	**54.81%**
PTDG	**Production, Transmission, Distribution and General Plant Ratio**	**Ratio Used**	**Total**	**Production**	**Transmission**	**Distribution**
	PTD Total		$ 3,755,888,074	$ 1,414,111,017	$ 283,206,605	$ 2,058,570,452
	Intangible Plant - Organization	DIST	-	-	-	-
	Intangible Plant - Franchises and Consents	DIRECT	48,460,534	48,460,534	-	-
	Intangible Plant - Miscellaneous	DIRECT	123,314,826	2,904,530	7,417,801	112,992,495
	General Plant Total		242,190,117	62,630,724	20,575,380	158,984,013
	TOTAL		$ 4,169,853,551	$ 1,528,106,805	$ 311,199,786	$ 2,330,546,960
	PTDG RATIO		**100%**	**36.65%**	**7.46%**	**55.89%**
TD	**Transmission and Distribution Plant Ratio**	**Ratio Used**	**Total**	**Production**	**Transmission**	**Distribution**
	Total Transmission Plant	TRANS	$ 283,206,605	$ -	$ 283,206,605	$ -
	Total Distribution Plant	DIST	2,058,570,452	-	-	2,058,570,452
	TOTAL		$ 2,341,777,057	$ -	$ 283,206,605	$ 2,058,570,452
	TD RATIO		**100%**	**0.00%**	**12.09%**	**87.91%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Portland General Electric
End of Year Report Period:	2006
ASC Filing Date:	5/7/2006

Amended BPA: 7-8-2008
Revised Amended BPA: 8-4-2008

TABLE 211: Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
GPM	**Maintenance of General Plant Ratio**					
	Structures and Improvements	PTD	$ 56,435,602	$ 21,248,292	$ 4,255,434	$ 30,931,876
	Furniture and Equipment	LABOR	36,822,574	11,448,061	1,928,782	23,445,731
	Communication Equipment	PTD	53,261,072	20,053,065	4,016,064	29,191,943
	Miscellaneous Equipment	DIST	267,571	-	-	267,571
	TOTAL		$ 146,786,819	$ 52,749,418	$ 10,200,280	$ 83,837,120
	GPM RATIO		**100%**	**35.94%**	**6.95%**	**57.11%**

SUMMARY RATIO TABLE

		Production	Transmission	Distribution
Conservation Functionalization	**CONS**	**70.00%**	**0.00%**	**30.00%**
Direct to Distribution	**DIST**	**0.00%**	**0.00%**	**100.00%**
Direct to Production	**PROD**	**100.00%**	**0.00%**	**0.00%**
Direct to Transmission	**TRANS**	**0.00%**	**100.00%**	**0.00%**
Direct Allocation	**DIRECT**	**0.00%**	**0.00%**	**0.00%**
General Plant	**GP**	**25.86%**	**8.50%**	**65.64%**
Maintenance of General Plant	**GPM**	**35.94%**	**6.95%**	**57.11%**
Labor Ratios	**LABOR**	**31.09%**	**5.24%**	**63.67%**
Production, Transmission, Distribution	**PTD**	**37.65%**	**7.54%**	**54.81%**
Production, Transmission, Distribution, General	**PTDG**	**36.65%**	**7.46%**	**55.89%**
Transmission, Distribution	**TD**	**0.00%**	**12.09%**	**87.91%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

TABLE 21J

UTILITY NAME:	Portland General Electric	
End of Year Report Period:	2006	Amended BPA: 7-8-2008
ASC Filing Date:	5/7/2006	Revised Amended BPA: 8-4-2008

Purchased Power & Sales for Resale

FERC Form 1 Statistical Classification	FERC Form 1 Page Number	Purchased Power Settlement Total	Purchased Power MWh Purchased	Purchased Power - Base Period Minus 1 Settlement Total	Purchased Power - Base Period Minus 1 MWh Purchased	Purchased Power - Base Period Minus 2 Settlement Total	Purchased Power - Base Period Minus 2 MWh Purchased
RQ	326-327	$927,165	11,059				
LF	326-327	122,712,106	3,117,635				
IF	326-327	72,868,276	1,751,900				
SF	326-327	877,059,313	18,088,277				
LU	326-327	46,067,346	3,207,820				
IU	326-327	0	0				
OS	326-327	1,310,082	37,452				
EX	326-327	0	0				
NA	326-327	0	0				
AD	326-327	(10,503,506)	10,385				
TOTAL		**$1,110,440,782**	**26,224,528**	**$0**	**0**	**$0**	**0**

FERC Form 1 Statistical Classification	FERC Form 1 Page Number	Sales for Resale Settlement Total	Sales for Resale MWh Sold	Sales for Resale - Base Period Minus 1 Settlement Total	Sales for Resale - Base Period Minus 1 MWh Sold	Sales for Resale - Base Period Minus 2 Settlement Total	Sales for Resale - Base Period Minus 2 MWh Sold
RQ	310-311	$556,768	0				
LF	310-311	8,108,077	70,074				
IF	310-311	0	0				
SF	310-311	640,231,119	13,596,012				
LU	310-311	97,402	11,999				
IU	310-311	0	0				
OS	310-311	1,416,484	31,991				
EX	310-311	0	0				
NA	310-311	0	0				
AD	310-311	0	0				
TOTAL		**$650,409,850**	**13,710,076**	**$ -**	**-**	**$ -**	**-**

PGE **TABLE 21K: Forecasted Contract System Costs & ASC with New Additions and NLSL**

Date	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
	10	11	12	13	14
Fiscal Year	2009	2010	2011	2012	2013
Rate Period Mid-Point	TRUE	FALSE	FALSE	FALSE	FALSE
Contract System Cost					
Production	989,569,836	982,643,846	1,014,355,729	1,037,931,055	1,065,378,501
Transmission	114,363,956	114,881,485	115,645,517	116,453,938	117,336,870
NLSL Fully Allocated Cost ($/MWh)	73.34	69.45	69.50	68.78	67.98
(Less) New Large Single Load Costs (d)	24,127,751	22,847,185	22,864,160	22,628,883	22,365,495
Total Contract System Cost	1,079,806,041	1,074,678,147	1,107,137,086	1,131,756,110	1,160,349,876
Contract System Load (MWh)					
Total Retail Load @ Meter	18,238,510	18,639,757	19,049,832	19,468,928	19,897,245
(Less) New Large Single Load	328,992	328,992	328,992	328,992	328,992
Total Retail Load (Net of NLSL) (d)	17,909,518	18,310,765	18,720,840	19,139,936	19,568,253
Distribution Loss (f)	859,034	877,933	897,247	916,987	937,160
Total Contract System Load	18,768,552	19,188,698	19,618,087	20,056,923	20,505,413
Average System Cost $/MWh	57.53	56.01	56.43	56.43	56.59

	Rate Period Mid-Point			New Resources											
					(0.12)	3.33	(0.20)	1.60	(0.23)	0.84	(0.24)	2.21	(0.27)		0.00
Date		4/1/09		4/1/2009	4/1/2009	4/1/2009	4/1/2009	4/1/2009	4/1/2009	4/1/2009	4/1/2009	4/1/2009	4/1/2009		
Fiscal Year		2009		2009	2009	2009	2009	2009	2009	2009	2009	2009	2009		
NLSL Switch		1		0	1	0	1	0	1	0	1	0	1		
Contract System Cost															
Production		989,569,836		854,338,417	854,338,417	913,090,605	913,090,605	939,893,100	939,893,100	951,693,516	951,693,516	989,569,836	989,569,836		
Transmission		114,363,956		112,259,934	112,259,934	114,814,747	114,814,747	114,646,570	114,646,570	114,604,924	114,604,924	114,363,956	114,363,956		
(Less) New Large Single Load Costs (d)		24,127,751		0	18,906,591	0	21,523,320	0	22,435,021	0	22,898,182	0	24,127,751		
Total Contract System Cost		1,079,806,041		966,598,352	947,691,761	1,027,905,353	1,006,382,033	1,054,539,669	1,032,104,649	1,066,298,440	1,043,400,258	1,103,933,792	1,079,806,041		
Contract System Load (MWh)															
Total Retail Load @ Meter		18,238,510		18,238,510	18,238,510	18,238,510	18,238,510	18,238,510	18,238,510	18,238,510	18,238,510	18,238,510	18,238,510		
(Less) New Large Single Load		328,992		0	328,992	0	328,992	0	328,992	0	328,992	0	328,992		
Total Retail Load (Net of NLSL) (d)		17,909,518		18,238,510	17,909,518	18,238,510	17,909,518	18,238,510	17,909,518	18,238,510	17,909,518	18,238,510	17,909,518		
Distribution Loss (f)		859,034		859,034	859,034	859,034	859,034	859,034	859,034	859,034	859,034	859,034	859,034		
Total Contract System Load		18,768,552		19,097,544	18,768,552	19,097,544	18,768,552	19,097,544	18,768,552	19,097,544	18,768,552	19,097,544	18,768,552		
Average System Cost $/MWh		57.53		50.61	50.49	53.82	53.62	55.22	54.99	55.83	55.59	57.81	57.53		
							$ 3.13		$ 1.37		$ 0.60		$ 1.94		

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Tables for:

Puget Sound Energy

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	2006
ASC Filing Date:	7-May-08

Amended 7-8-2008

Revised Amended 8-4-2008

TABLE 22A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Number	Default	Optional				
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST		114,202	-	-	114,202
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD	14,250,583	13,651,704	61,533	537,346
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST	15,160,967	6,826,300	856,364	7,478,302
Total Intangible Plant					$ 29,525,752.00	$ 20,478,003.71	$ 917,897.09	$ 8,129,849.34
Production Plant:								
Steam Production	204-207	310-316	PROD		816,146,214	816,146,214	-	-
Nuclear Production	204-207	320-325	PROD		0	-	-	-
Hydraulic Production	204-207	330-336	PROD		164,854,647	164,854,647	-	-
Other Production	204-207	340-346	PROD		728,676,783	728,676,783	-	-
Total Production Plant					$ 1,709,677,644.00	$ 1,709,677,644.00	$ -	$ -
Transmission Plant: (i)								
Transmission Plant	204-207	350-359	TRANS		331,209,903	-	331,209,903	-
Total Transmission Plant					$ 331,209,903.00	$ -	$ 331,209,903.00	$ -
Distribution Plant:								
Distribution Plant	204-207	360-373	DIST		2,892,330,528	-	-	2,892,330,528
Total Distribution Plant					$ 2,892,330,528.00	$ -	$ -	$ 2,892,330,528.00
General Plant:								
Land and Land Rights	204-207	389	PTD		6,734,802	2,334,042	452,166	3,948,594
Structures and Improvements	204-207	390	PTD		30,937,105	10,721,698	2,077,077	18,138,329
Furniture and Equipment	204-207	391	LABOR		34,756,184	10,281,539	1,470,075	23,004,570
Transportation Equipment	204-207	392	TD		1,210,860	-	124,413	1,086,447
Stores Equipment	204-207	393	PTD		1,061,090	367,736	71,240	622,114
Tools and Garage Equipment	204-207	394	PTD		5,918,527	2,051,151	397,362	3,470,014
Laboratory Equipment	204-207	395	PTD		13,347,330	4,625,709	896,123	7,825,498
Power Operated Equipment	204-207	396	TD		1,216,046	-	124,945	1,091,101
Communication Equipment	204-207	397	PTD		41,613,080	14,421,611	2,793,849	24,397,620
Miscellaneous Equipment	204-207	398	PTD		449,935	155,931	30,208	263,796
Other Tangible Property	204-207	399	DIRECT	PTD	0	-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD		16,026	5,554	1,076	9,396
Total General Plant					$ 137,260,985	$ 44,964,972	$ 8,438,534	$ 83,857,479
Total Electric Plant In-Service					$ 5,100,004,812	$ 1,775,120,620	$ 340,566,334	$ 2,984,317,856

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME: **Puget Sound Energy, Inc.**
End of Year Report Period: **2006**
ASC Filing Date: **7-May-08** **Amended 7-8-2008**
Revised Amended 8-4-2008

TABLE 22A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Number	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD		454,497,985	454,497,985	-	-
Nuclear Production Plant	219	108	PROD		0	-	-	-
Hydraulic Production Plant	219	108	PROD		119,491,099	119,491,099	-	-
Other Production Plant	219	108	PROD		125,996,078	125,996,078	-	-
Transmission Plant (i)	219	108	TRANS		123,295,807	-	123,295,807	-
Distribution Plant	219	108	DIST		1,073,299,571	-	-	1,073,299,571
General Plant	219	108	GP		68,125,305	22,316,993	4,188,209	41,620,103
Amortization of Intangible Plant - Account 301	219	111	DIST		0	-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD	*1,347,416*	1,022,252	33,410	291,755
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST	*5,397,587*	3,253,313	220,318	1,923,956
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	108	DIST			-	-	-
Capital Lease - Common Plant	219	108	DIRECT		*0*	-	-	-
Leasehold Improvements	200-201	108	DIRECT	DIST	*0*	-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT		16,674,463	5,056,599	1,008,028	10,609,837
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST	119,309,921	41,790,839	7,857,405	69,661,678
Amortization of Acquisition Adjustments	200-201	115	DIRECT		35,509,127	34,618,339	641,589	249,199
Depreciation and Amortization Reserve (Other)			DIRECT	DIRECT		-	-	-
Total Depreciation and Amortization Reserve					**$ 2,142,944,360**	**$ 808,043,496**	**$ 137,244,765**	**$ 1,197,656,098**
Total Net Plant					**$ 2,957,060,452**	**$ 967,077,124**	**$ 203,321,569**	**$ 1,786,661,758**

(Total Electric Plant In-Service) - (Total Depreciation & Amortization)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	2006
ASC Filing Date:	7-May-08

Amended 7-8-2008

Revised Amended 8-4-2008

TABLE 22A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Number	Default	Optional				
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation: Automatic Input from Sch 1A				43,830,436	16,732,533	7,572,081	19,525,822
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST		8,250,089	-	-	8,250,089
(Utility Plant) Completed Construction - Not Clas	200-201	106	PTD		0	-	-	-
Nuclear Fuel		120.1-120	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	07 & 120	DIST		148,242,338	-	-	148,242,338
Common Plant	356 & 356.1		DIRECT		283,447,445	96,395,371	18,181,209	168,870,865
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST	77,871,127	76,622,597	946,172	302,358
Total					**$ 517,810,999**	**$ 173,017,968**	**$ 19,127,382**	**$ 325,665,650**
Other Property and Investments								
Investment in Associated Companies	110-111	123	DIRECT	DIST	65,430,548	-	-	65,430,548
Other Investment	110-111	124	DIST		56,933,008	-	-	56,933,008
Long-Term Portion of Derivative Assets	110-111	175	DIST		0	-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST		6,934,092	-	-	6,934,092
Total					**$ 129,297,648**	**$ -**	**$ -**	**$ 129,297,648**
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD		7,556,054	7,556,054	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD		0	-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD		41,499,686	14,382,313	2,786,235	24,331,138
Merchandise (Major Only)	110-112	155	DIST		0	-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST		0	-	-	-
EPA Allowance Inventory	110-112	158.1	PROD		0	-	-	-
EPA Allowances Withheld	110-112	158.2	PROD		0	-	-	-
Stores Expense Undistributed	110-111	163	PTD		2,001,197	693,544	134,358	1,173,296
Prepayments	110-111	165	PTD		8,637,405	2,993,417	579,904	5,064,084
Derivative Instrument Assets	110-111	175	DIST		897,436	-	-	897,436
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST		0	-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST		22,862,757	-	-	22,862,757
(Less) Long-Term Portion of Derivative Assets -	110-112	176	DIST		6,934,092	-	-	6,934,092
Total					**$ 76,520,443**	**$ 25,625,327**	**$ 3,500,497**	**$ 47,394,618**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	2006
ASC Filing Date:	7-May-08

Amended 7-8-2008

Revised Amended 8-4-2008

TABLE 22A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Number	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG		23,026,925	8,014,810	1,537,684	13,474,431
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST	101,121,230	-	4,145,984	96,975,246
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST	43,391,364	43,391,364	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST	500,341,523	247,155,827	10,944,321	242,241,375
Preliminary Survey and Investigation Charges (El	110-111	183	DIST		657,177	-	-	657,177
Preliminary Natural Gas Survey and Investigation	110-111	183.1	DIST		0	-	-	-
Other Preliminary Survey and Investigation Charg	110-111	183.2	DIST		0	-	-	-
Clearing Accounts	110-111	184	DIST		0	-	-	-
Temporary Facilities	110-111	185	PTDG		(231,994)	(80,748)	(15,492)	(135,754)
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST	89,181,974	38,411,622	4,311,081	46,459,267
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT	DIRECT	1,870,213	772,882	149,728	947,603
Research, Development, and Demonstration Expe	110-111	188	DIST		0	-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG		21,266,360	7,402,023	1,420,118	12,444,219
Accumulated Deferred Income Taxes	110-111	190	DIST		161,904,008	-	-	161,904,008
Total					**$ 942,528,781**	**$ 345,067,781**	**$ 22,493,423**	**$ 574,967,574**
Total Assets and Other Debits					**$ 1,709,988,307**	**$ 560,443,609**	**$ 52,693,384**	**$ 1,096,851,312**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	2006
ASC Filing Date:	7-May-08

Amended 7-8-2008

Revised Amended 8-4-2008

TABLE 22A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Number	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Liabilities and Other Credits (Comparative Balance Sheet)								
CURRENT AND ACCRUED LIABILITIES								
Derivative Instrument Liabilities	112-113	244	DIST		917,995	-	-	917,995
(less) Long-Term Portion of Derivative Instrumen	112-114	244	DIST		0	-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST		70,092,060	-	-	70,092,060
(less) Long-Term Portion of Derivative Instrumen	112-114	245	DIST		0	-	-	-
Total					**$ 71,010,055**	**$ -**	**$ -**	**$ 71,010,055**
DEFERRED CREDITS								
Customer Advances for Construction	112-113	252	DIST		79,267,139	-	-	79,267,139
Other Deferred Credits	112-113	253	DIRECT	DIST	83,627,599	27,538,363	5,100,168	50,989,069
Other Regulatory Liabilities	112-113	254	DIRECT	DIST	15,001,517	11,384,386	548,890	3,068,242
Accumulated Deferred Investment Tax Credits	112-113	255	DIST		79,267,139	-	-	79,267,139
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT	DIRECT	2,951,835	1,024,164	197,902	1,729,769
Unamortized Gain on Reacquired Debt	112-113	257	PTDG		494,072	171,968	32,993	289,111
Accumulated Deferred Income Taxes-Accel. Amo	112-113	281	DIST		0	-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST		611,456,563	-	-	611,456,563
Accumulated Deferred Income Taxes-Other	112-113	283	DIST		296,532,901	-	-	296,532,901
Total					**$ 1,168,598,766**	**$ 40,118,881**	**$ 5,879,953**	**$ 1,122,599,933**
Total Liabilities and Other Credits					**$ 1,239,608,821**	**$ 40,118,881**	**$ 5,879,953**	**$ 1,193,609,988**
Total Rate Base					**$ 3,427,439,939**	**$ 1,487,401,852**	**$ 250,135,000**	**$ 1,689,903,082**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Amended 7-8-2008
Revised Amended 8-4-2008

TABLE 22B: Schedule 1A: Cash Working Capital (f)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	1,144,649,017	1,144,649,017	-	-
Total Transmission O&M (i)	57,969,332	-	57,969,332	-
Total Distribution O&M	65,438,100	-	-	65,438,100
Total Customer & Sales	71,732,129	30,809,083	-	40,923,046
Total Administrative and General O&M	70,097,636	17,644,889	2,607,319	49,845,428
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	1,059,242,723	1,059,242,723	-	-
Revised Total O&M Expenses	**$ 350,643,491**	**$ 133,860,267**	**$ 60,576,651**	**$ 156,206,574**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 43,830,436**	**$ 16,732,533**	**$ 7,572,081**	**$ 19,525,822**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.	
End of Year Report Period:	31-Dec-06	
ASC Filing Date:	7-May-08	Amended 7-8-2008

TABLE 22C: Schedule 2: Capital Structure and Rate of Return (b) **Revised Amended 8-4-2008**

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:	10.866%
Multi-Jurisdiction Investor-Owned Utility Return Calculation:	
Consumer-Owned Utility Return Calculation:	
Rate of Return :	**10.866%**

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order

Note: Multi-jurisdictional utilities must begin on Page 2

Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**
Debt	$ 56.0	56.0%	6.83%	3.820%
Preferred Equity	$ 0.1	0.1%	7.61%	0.004%
Common Equity	$ 44.0	44.0%	10.40%	4.576%
Weighted Cost of Capital	**$ 100.0**	**100.000%**		**8.400%**

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	**35%**	
Federal Income Tax Factor		**2.466%**

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital **10.866%**

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 3,427,439,939	$ 1,487,401,852	$ 250,135,000	$ 1,689,903,082
Federal Income Tax Adjusted Weighted Cost of Capital	10.866%	10.866%	10.866%	10.866%
Federal Income Tax Adjusted Return on Rate Base	**$372,430,897**	**$161,623,374**	**$27,180,054**	**$183,627,469**

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Amended 7-8-2008

TABLE 22C: Schedule 2: Capital Structure and Rate of Return (b)

Revised Amended 8-4-2008

Multi-Jurisdiction Investor-Owned Utility Return Calculation

Step 1:

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 1

	Capitalization Structure		Effective Cost		Jurisdictional	Effective Cost -	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**	**Allocation**	**Weighted State Allocation**	
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 2

Component	Amount	Percent	Embedded	Weighted			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 3

Component	Amount	Percent	Embedded	Weighted			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Jurisdiction	Rate Base	Weighted cost	%	Weighted Return		
Total						

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Amended 7-8-2008

TABLE 22C: Schedule 2: Capital Structure and Rate of Return (b)

Revised Amended 8-4-2008

Multi-Jurisdiction Investor-Owned Utility Return Calculation *(continued)*

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) **35%**

Federal Income Tax Factor

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 3,427,439,939	$ 1,487,401,852	$ 250,135,000	$ 1,689,903,082
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Amended 7-8-2008

TABLE 22C: Schedule 2: Capital Structure and Rate of Return (b)

Revised Amended 8-4-2008

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

Debt Issue	Original Amount	Year Issued	Year Due	Interest Rate	Interest Expense
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	$ -				$ -

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 3,427,439,939	$ 1,487,401,852	$ 250,135,000	$ 1,689,903,082
Weighted Cost of Debt				
Return on Rate Base				

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Amended 7-8-2008
Revised Amended 8-4-2008

TABLE 22D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD		50,018,163	50,018,163	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD		12,178,423	12,178,423	-	-
Steam Power - Maintenance	320-323	510-515	PROD		19,991,699	19,991,699	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD			-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD			-	-	-
Nuclear - Maintenance	320-323	528-532	PROD			-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540	PROD		4,112,341	4,112,341	-	-
Hydraulic - Maintenance	320-323	541-545	PROD		3,776,501	3,776,501	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD		47,301,858	47,301,858	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550	PROD		16,574,506	16,574,506	-	-
Other Power - Maintenance	320-323	551-554	PROD		8,418,999	8,418,999	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	320-323	555	PROD		961,922,702	961,922,702	-	-
System Control and Load Dispatching	320-323	556	PROD		815,816	815,816	-	-
Other Expenses	320-323	557	PROD		19,538,009	19,538,009	-	-
BPA REP Reversal	327	555	PROD		0	-	-	-
Public Purpose Charges (h)			DIRECT			-	-	-
Total Production Expense					**$ 1,144,649,017**	**$ 1,144,649,017**	**$ -**	**$ -**
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS		52,660,736	-	52,660,736	-
Total Operations less Wheeling	320-323	560-567	TRANS		2,541,280	-	2,541,280	-
Total Maintenance	320-323	568-573	TRANS		2,767,316	-	2,767,316	-
Total Transmission Expense					**$ 57,969,332**	**$ -**	**$ 57,969,332**	**$ -**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.	
End of Year Report Period:	31-Dec-06	
ASC Filing Date:	7-May-08	Amended 7-8-2008 Revised Amended 8-4-2008

TABLE 22D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Distribution Expense:								
Total Operations	320-323	580-589	DIST		19,484,024	-	-	19,484,024
Total Maintenance	320-323	590-598	DIST		45,954,076	-	-	45,954,076
Total Distribution Expense					$ 65,438,100	$ -	$ -	$ 65,438,100
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST		35,267,225	-	-	35,267,225
Customer Service and Information	320-323	906-907	DIST		0	-	-	-
Customer Assistance Expenses (Major only)	320-323	908	DIRECT		35,272,099	30,809,083	-	4,463,016
Customer Service and Information	320-323	909-910	DIST		636,810	-	-	636,810
Total Sales Expense	320-323	911-917	DIST		555,995	-	-	555,995
Total Customer and Sales Expenses					$ 71,732,129	$ 30,809,083	$ -	$ 40,923,046
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR		13,241,645	3,917,130	560,079	8,764,436
Office Supplies & Expenses	320-323	921	LABOR		15,215,027	4,500,894	643,547	10,070,586
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR		108,476	32,089	4,588	71,799
Outside Services Employed	320-323	923	LABOR		5,292,007	1,565,476	223,835	3,502,696
Property Insurance	320-323	924	PTDG		2,580,565	898,198	172,324	1,510,043
Injuries and Damages	320-323	925	LABOR		4,632,927	1,370,508	195,958	3,066,461
Employee Pensions & Benefits	320-323	926	LABOR		14,541,949	4,301,785	615,078	9,625,087
Franchise Requirements	320-323	927	DIST		0	-	-	-
Regulatory Commission Expenses	320-323	928	DIST		6,087,900	-	-	6,087,900
(Less) Duplicate Charges - Credit	320-323	929	PTDG		0	-	-	-
General Advertising Expenses	320-323	930.1	DIRECT	DIST	0	-	-	-
Miscellaneous General Expenses	320-323	930.2	DIST		2,560,020	-	-	2,560,020
Rents	320-323	931	DIST		2,653,105	-	-	2,653,105
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM		3,400,967	1,122,988	201,086	2,076,893
Total Administration and General Expenses					$ 70,097,636	$ 17,644,889	$ 2,607,319	$ 49,845,428

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Amended 7-8-2008
Revised Amended 8-4-2008

TABLE 22D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Total Operations and Maintenance					$ 1,409,886,214	$ 1,193,102,990	$ 60,576,651	$ 156,206,574
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)					163,622,427			
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST		0	-	-	0
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD	*59,386*	20,581	3,987	34,818
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST	*1,906,918*	795,459	87,568	1,023,892
Steam Production Plant	336	403	PROD		22,420,574	22,420,574	-	-
Nuclear Production Plant	336	403	PROD		0	-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD		11,167,925	11,167,925	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD		0	-	-	-
Other Production Plant	336	403	PROD		13,939,992	13,939,992	-	-
Transmission Plant (i)	336	403	TRANS		7,546,998	-	7,546,998	-
Distribution Plant	336	403	DIST		78,846,577	-	-	78,846,577
General Plant	336	403	GP		6,410,063	2,099,856	394,078	3,916,129
Common Plant - Electric	336	403	DIRECT		4,168,361	1,348,616	256,263	2,563,482
Common Plant - Electric	336	404	DIRECT		20,273,238	7,087,471	1,054,382	12,131,386
Depreciation Expense for Asset Retirement Costs	336	403	DIRECT	DIRECT	531,927	72,243	34,907	424,777
Amortization of Limited Term Electric Plant	336	404	DIRECT	DIRECT	426,598	-	426,598	-
Amortization of Plant Acquisition Adjustments (Electric)	200-201	114	DIRECT		12,456,890	4,905,412	278,598	7,272,877
Total Depreciation and Amortization					$ 180,155,448	$ 63,858,128	$ 10,083,379	$ 106,213,938
Total Operating Expenses					$ 1,590,041,662	$ 1,256,961,118	$ 70,660,029	$ 262,420,512
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Amended 7-8-2008

Revised Amended 8-4-2008

TABLE 22E: Schedule 3A Items: Taxes (Including Income Taxes)

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Funct. Method	Total	Production	Transmission	Distribution/ Other
FEDERAL							
Income Tax (Included on Schedule 2)	262	409.1	DIST	0	-	-	-
Employment Tax	262	408.1	LABOR	6,792,178	2,009,255	287,287	4,495,635
Other Federal Taxes	262	408.1	DIST	0	-	-	-
TOTAL FEDERAL				**$ 6,792,178**	**$ 2,009,255**	**$ 287,287**	**$ 4,495,635**
STATE AND OTHER							
Property	262	408.1	PTDG	20,431,184	7,111,330	1,364,346	11,955,508
Unemployment	262	408.1	LABOR		-	-	-
State Income, B&O, et.	262	409.1	DIST	64,010,061	-	-	64,010,061
Franchise Fees	262	408.1	DIST		-	-	-
Regulatory Commission	262	408.1	DIST		-	-	-
City/Municipal	262	408.1	DIST	54,092,045	-	-	54,092,045
Other	262	408.1	DIST	11,655,713	-	-	11,655,713
TOTAL STATE AND OTHER TAXES				**$ 150,189,003**	**$ 7,111,330**	**$ 1,364,346**	**$ 141,713,327**
TOTAL TAXES				**$ 156,981,181**	**$ 9,120,585**	**$ 1,651,634**	**$ 146,208,962**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Amended 7-8-2008
Revised Amended 8-4-2008

TABLE 22F: Schedule 3B Other Included Items

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	DIST	-	-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST	-	-	-	-
Gain from Disposition of Utility Plant	114	411.6	DIRECT	DIST	969,412	335,964	65,085	568,363
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST	(376,588)	(130,512)	(25,284)	(220,792)
Gain from Disposition of Allowances	114	411.8	PROD		411,056	411,056	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD		-	-	-	-
Miscellaneous Nonoperating Income	114	421	PROD	PROD	3,889,163	3,889,163	-	-
Total Other Included Items					**$ 5,646,219**	**$ 4,766,695**	**$ 90,369**	**$ 789,156**
Sales for Resale:								
Sales for Resale	310	447	PROD		202,397,803	202,397,803	-	-
Total Sales for Resale					**$ 202,397,803**	**$ 202,397,803**	**$ -**	**$ -**
Other Revenues:								
Forfeited Discounts	300	450	DIST		2,857,384	-	-	2,857,384
Miscellaneous Service Revenues	300	451	DIST		12,159,569	-	-	12,159,569
Sales of Water and Water Power	300	453	PROD		-	-	-	-
Rent from Electric Property	300	454	TD		11,031,178	-	1,133,423	9,897,755
Interdepartmental Rents	300	455	DIST		-	-	-	-
Other Electric Revenues	300	456	DIRECT	PROD	19,606,394	16,710,647	2,418,113	477,634
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS		9,920,949	-	9,920,949	-
Total Other Revenues					**$ 55,575,474**	**$ 16,710,647**	**$ 13,472,485**	**$ 25,392,342**
Total Other Included Items					**$ 263,619,496**	**$ 223,875,145**	**$ 13,562,854**	**$ 26,181,498**

(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Amended 7-8-2008

Revised Amended 8-4-2008

TABLE 22G: Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses *(From Schedule 3)*	$ 1,590,041,662	$ 1,256,961,118	$ 70,660,029	$ 262,420,512
Federal Income Tax Adjusted Return on Rate Base *(From Schedule 2)*	$ 372,430,897	$ 161,623,374	$ 27,180,054	$ 183,627,469
State and Other Taxes *(From Schedule 3a)*	$ 156,981,181	$ 9,120,585	$ 1,651,634	$ 146,208,962
Total Other Included Items *(From Schedule 3b)*	$ 263,619,496	$ 223,875,145	$ 13,562,854	$ 26,181,498
Total Cost *(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*	**$ 1,855,834,244**	**$ 1,203,829,932**	**$ 85,928,863**	**$ 566,075,445**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	**Puget Sound Energy, Inc.**
End of Year Report Period:	**31-Dec-06**
ASC Filing Date:	**7-May-08**

Amended 7-8-2008

Revised Amended 8-4-2008

TABLE 22G: Schedule 4: Average System Cost

Contract System Cost		
Production	$	1,203,829,932
Transmission	$	85,928,863
(Less) New Large Single Load Costs (d)	$	-
Total Contract System Cost	**$**	**1,289,758,795**
Contract System Load (MWh)		
Total Retail Load		21,099,045
(Less) New Large Single Load		0
Total Retail Load (Net of NLSL) (d)		21,099,045
Distribution Loss (f)		1,052,842	4.990%
Total Contract System Load		**22,151,887**
Average System Cost $/MWh		**58.22**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Amended 7-8-2008

Revised Amended 8-4-2008

TABLE 22H: Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	7,404,499
Transmission	354-355	983,521
Distribution	354-355	8,376,318
Customer Accounts	354-355	9,350,899
Customer Service and Information	354-355	1,056,792
Sales	354-355	396,464
Administrative and General	354-355	15,933,099
TOTAL Operation		**$43,501,592**
Maintenance		
Production	354-355	2,678,586
Transmission	354-355	294,771
Distribution	354-355	9,467,051
Administrative and General	354-355	730,527
TOTAL Maintenance		**$13,170,935**
Operation and Maintenance		
Production (Total of lines 16 and 26)	354-355	10,083,085
Transmission (Total of lines 17 and 27)	354-355	1,278,292
Distribution (Total of lines 18 and 28)	354-355	17,843,369
Customer Accounts (From line 20)	354-355	9,350,899
Customer Service and Information (From line 20)	354-355	1,056,792
Sales (From line 21)	354-355	396,464
Administrative and General (Total of lines 22 and 29)	354-355	16,663,626
TOTAL Operation and Maintenance		**$56,672,527**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Revised Amended 8-4-2008

TABLE 22I: Ratio Table

Labor Ratio Input:	Ratio Used	Total	Production	Transmission	Distribution
Production	PROD	$ 10,083,085	$ 10,083,085	$ -	$ -
Transmission	TRANS	1,278,292	-	1,278,292	-
Distribution	DIST	17,843,369	-	-	17,843,369
Customer Accounts	DIST	9,350,899	-	-	9,350,899
Customer Service and Informational	DIRECT	1,056,792	906,705	-	150,087
Sales	DIST	396,464	-	-	396,464
Administrative & General	PTD	16,663,626	5,775,019	1,118,774	9,769,832
Total Labor		$ 56,672,527	$ 16,764,809	$ 2,397,066	$ 37,510,651
Labor Ratio		**100%**	**30%**	**4%**	**66%**

GP **General Plant Ratio**	Ratio Used	Total	Production	Transmission	Distribution
Land and Land Rights	PTD	$ 6,734,802	$ 2,334,042	$ 452,166	$ 3,948,594
Structures and Improvements	PTD	30,937,105	10,721,698	2,077,077	18,138,329
Furniture and Equipment	LABOR	34,756,184	10,281,539	1,470,075	23,004,570
Transportation Equipment	TD	1,210,860	-	124,413	1,086,447
Stores Equipment	PTD	1,061,090	367,736	71,240	622,114
Tools and Garage Equipment	PTD	5,918,527	2,051,151	397,362	3,470,014
Laboratory Equipment	PTD	13,347,330	4,625,709	896,123	7,825,498
Power Operated Equipment	TD	1,216,046	-	124,945	1,091,101
Communication Equipment	PTD	41,613,080	14,421,611	2,793,849	24,397,620
Miscellaneous Equipment	PTD	449,935	155,931	30,208	263,796
Other Tangible Property	DIRECT	-	-	-	-
Asset Retirement Costs for General Plant	PTD	16,026	5,554	1,076	9,396
TOTAL		$ 137,260,985	$ 44,964,972	$ 8,438,534	$ 83,857,479
RATIO (GP)		**100%**	**33%**	**6%**	**61%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Revised Amended 8-4-2008

TABLE 22I: Ratio Table

PTD	Production, Transmission, Distribution Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Steam Production	PROD	$ 816,146,214	$ 816,146,214	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	164,854,647	164,854,647	-	-
	Other Production	PROD	728,676,783	728,676,783	-	-
	Total Production Plant		1,709,677,644	1,709,677,644	-	-
	Transmission Plant	TRANS	331,209,903	-	331,209,903	-
	Total Distribution Plant	DIST	2,892,330,528	-	-	2,892,330,528
	TOTAL		$ 4,933,218,075	$ 1,709,677,644	$ 331,209,903	$ 2,892,330,528
	PTD Ratio		**100%**	**35%**	**7%**	**59%**

PTDG	Production, Transmission, Distribution and General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	PTD Total		$ 4,933,218,075	$ 1,709,677,644	$ 331,209,903	$ 2,892,330,528
	Intangible Plant - Organization	DIST	114,202	-	-	114,202
	Intangible Plant - Franchises and Consents	DIRECT	14,250,583	13,651,704	61,533	537,346
	Intangible Plant - Miscellaneous	DIRECT	15,160,967	6,826,300	856,364	7,478,302
	General Plant Total		137,260,985	44,964,972	8,438,534	83,857,479
	TOTAL		$ 5,100,004,812	$ 1,775,120,620	$ 340,566,334	$ 2,984,317,856
	PTDG RATIO		**100%**	**35%**	**7%**	**59%**

TD	Transmission and Distribution Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Total Transmission Plant	TRANS	$ 331,209,903	$ -	$ 331,209,903	$ -
	Total Distribution Plant	DIST	2,892,330,528	-	-	2,892,330,528
	TOTAL		$ 3,223,540,431	$ -	$ 331,209,903	$ 2,892,330,528
	TD RATIO		**100%**	**0%**	**10%**	**90%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Puget Sound Energy, Inc.
End of Year Report Period:	31-Dec-06
ASC Filing Date:	7-May-08

Revised Amended 8-4-2008

***TABLE 22I*: Ratio Table**

GPM	Maintenance of General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Structures and Improvements	PTD	$ 30,937,105	$ 10,721,698	$ 2,077,077	$ 18,138,329
	Furniture and Equipment	LABOR	34,756,184	10,281,539	1,470,075	23,004,570
	Communication Equipment	PTD	41,613,080	14,421,611	2,793,849	24,397,620
	Miscellaneous Equipment	PTD	449,935	155,931	30,208	263,796
	TOTAL		$ 107,756,304	$ 35,580,780	$ 6,371,209	$ 65,804,315
	GPM RATIO		**100%**	**33%**	**6%**	**61%**

SUMMARY RATIO TABLE

		Production	Transmission	Distribution
Conservation Functionalization	**CONS**	**70.00%**	**0.00%**	**30.00%**
Direct to Distribution	**DIST**	**0.00%**	**0.00%**	**100.00%**
Direct to Production	**PROD**	**100.00%**	**0.00%**	**0.00%**
Direct to Transmission	**TRANS**	**0.00%**	**100.00%**	**0.00%**
Direct Allocation	**DIRECT**	**0.00%**	**0.00%**	**0.00%**
General Plant	**GP**	**32.76%**	**6.15%**	**61.09%**
Maintenance of General Plant	**GPM**	**33.01967%**	**5.91261%**	**61.06772%**
Labor Ratios	**LABOR**	**29.58%**	**4.23%**	**66.19%**
Production, Transmission, Distribution	**PTD**	**34.66%**	**6.71%**	**58.63%**
Production, Transmission, Distribution, General	**PTDG**	**34.81%**	**6.68%**	**58.52%**
Transmission, Distribution	**TD**	**0.00%**	**10.27%**	**89.73%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

TABLE 22J	UTILITY NAME:	Puget Sound Energy, Inc.	
	End of Year Report Period:	31-Dec-06	Amended 7-8-2008
	ASC Filing Date:	7-May-08	**Revised Amended 8-4-2008**

Purchased Power & Off-System Sales

FERC Form 1		Purchased Power	
Statistical Classification	Page Number	Settlement Total	MWh Purchased
RQ	326-327	$ -	-
LF	326-327	$ 139,481,412	6,935,897
IF	326-327	$ -	-
SF	326-327	$ -	-
LU	326-327	$ 282,182,918	2,689,484
IU	326-327	$ -	-
OS	326-327	$ 544,755,760	10,637,629
EX	326-327	$ (4,497,388)	-
NA	326-327	$ -	-
AD	326-327	$ -	-
TOTAL		**$ 961,922,702**	**20,263,010**

FERC Form 1		Sales for Resale	
Statistical Classification	Page Number	Settlement Total	MWh Purchased
RQ	310-311	$ 362,031	7,512
LF	310-311	$ -	-
IF	310-311	$ -	-
SF	310-311	$ -	-
LU	310-311	$ -	-
IU	310-311	$ -	-
OS	310-311	$ 202,035,772	4,489,127
EX	310-311	$ -	-
NA	310-311	$ -	-
AD	310-311	$ -	-
TOTAL		**$ 202,397,803**	**4,496,639**

PSE

TABLE 22K: Forecasted Contract System Costs & ASC with New Additions and NLSL

Date	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
	6	7	8	9	10
Fiscal Year	2009	2010	2011	2012	2013
Rate Period Mid-Point	**TRUE**	**FALSE**	**FALSE**	**FALSE**	**FALSE**
Contract System Cost					
Production	1,287,048,182	1,299,213,211	1,324,035,089	1,346,357,375	1,369,844,418
Transmission	87,615,204	87,580,901	87,751,169	87,991,341	88,294,956
NLSL Fully Allocated Cost ($/MWh)					
(Less) New Large Single Load Costs (d)	**0**	**0**	**0**	**0**	**0**
Total Contract System Cost	1,374,663,386	1,386,794,112	1,411,786,258	1,434,348,715	1,458,139,373
Contract System Load (MWh)					
Total Retail Load @ Meter	21,927,453	22,118,040	22,279,295	22,425,579	22,561,132
(Less) New Large Single Load	**0**	**0**	**0**	**0**	**0**
Total Retail Load (Net of NLSL) (d)	21,927,453	22,118,040	22,279,295	22,425,579	22,561,132
Distribution Loss (f)	1,094,180	1,103,690	1,111,737	1,119,036	1,125,800
Total Contract System Load	23,021,633	23,221,730	23,391,032	23,544,615	23,686,933
Average System Cost $/MWh	**59.71**	**59.72**	**60.36**	**60.92**	**61.56**

	Rate Period Mid-Point
Date	**4/1/09**
Fiscal Year	2009
NLSL Switch	1
Contract System Cost	
Production	1,287,048,182
Transmission	87,615,204
(Less) New Large Single Load Costs (d)	0
Total Contract System Cost	1,374,663,386
Contract System Load (MWh)	
Total Retail Load @ Meter	21,927,453
(Less) New Large Single Load	**0**
Total Retail Load (Net of NLSL) (d)	21,927,453
Distribution Loss (f)	1,094,180
Total Contract System Load	23,021,633
Average System Cost $/MWh	**59.71**

Tables for:

Snohomish County PUD

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Snohomish	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	6/30/2008	Revised Amended 8-4-2008

TABLE 23A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST			-	-	-
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD	3,009	-	-	3,009
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST	61,978,198	5,420,464	14,803,486	41,754,247
Total Intangible Plant					$ 61,981,207	$ 5,420,464	$ 14,803,486	$ 41,757,256
Production Plant:								
Steam Production	204-207	310-317	PROD		132,438,035	132,438,035	-	-
Nuclear Production	204-207	320-326	PROD			-	-	-
Hydraulic Production	204-207	330-337	PROD		208,007,068	208,007,068	-	-
Other Production	204-207	340-347	PROD			-	-	-
Total Production Plant					$ 340,445,103	$ 340,445,103	$ -	$ -
Transmission Plant: (i)								
Transmission Plant	204-207	350-359.1	TRANS		86,002,829	-	86,002,829	-
Total Transmission Plant					$ 86,002,829	$ -	$ 86,002,829	$ -
Distribution Plant:								
Distribution Plant	204-207	360-374	DIST		719,129,388	-	-	719,129,388
Total Distribution Plant					$ 719,129,388	$ -	$ -	$ 719,129,388
General Plant:								
Land and Land Rights	204-207	389	PTD		2,885,820	857,614	216,649	1,811,556
Structures and Improvements	204-207	390	PTD		60,594,190	18,007,510	4,549,035	38,037,644
Furniture and Equipment	204-207	391	LABOR		10,268,103	1,406,339	315,150	8,546,615
Transportation Equipment	204-207	392	TD		20,302,164	-	2,168,642	18,133,522
Stores Equipment	204-207	393	PTD		862,334	256,270	64,739	541,325
Tools and Garage Equipment	204-207	394	PTD		2,719,250	808,112	204,144	1,706,993
Laboratory Equipment	204-207	395	PTD		2,244,491	667,023	168,502	1,408,966
Power Operated Equipment	204-207	396	TD		820,827	-	87,679	733,148
Communication Equipment	204-207	397	PTD		32,740,851	9,729,996	2,457,980	20,552,876
Miscellaneous Equipment	204-207	398	PTD		64,873	19,279	4,870	40,724
Other Tangible Property	204-207	399	DIRECT	PTD		-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD			-	-	-
Total General Plant					$ 133,502,903	$ 31,752,143	$ 10,237,392	$ 91,513,368
Total Electric Plant In-Service					$ 1,341,061,430	$ 377,617,710	$ 111,043,707	$ 852,400,012

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Snohomish	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	6/30/2008	Revised Amended 8-4-2008

TABLE 23A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD			-	-	-
Nuclear Production Plant	219	108	PROD			-	-	-
Hydraulic Production Plant	219	108	PROD			-	-	-
Other Production Plant	219	108	PROD		128,982,341	128,982,341	-	-
Transmission Plant (i)	219	108	TRANS		24,934,186	-	24,934,186	-
Distribution Plant	219	108	DIST		235,284,470	-	-	235,284,470
General Plant	219	108	GP		73,688,545	17,525,980	5,650,652	50,511,913
Amortization of Intangible Plant - Account 301	219	111	DIST			-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD	60	-	-	-
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST	35,759,420	3,127,433	8,540,719	24,091,419
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	111	DIST			-	-	-
Capital Lease - Common Plant	219	108	DIRECT			-	-	-
Leasehold Improvements	200-201	108	DIRECT	DIST		-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT			-	-	-
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST		-	-	-
Amortization of Acquisition Adjustments	200-201	115	DIRECT			-	-	-
Depreciation and Amortization Reserve (Other)			DIRECT					
Total Depreciation and Amortization Reserve					$ 498,649,022	$ 149,635,754	$ 39,125,557	$ 309,887,802
Total Net Plant					$ 842,412,408	$ 227,981,956	$ 71,918,149	$ 542,512,210
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Snohomish	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	6/30/2008	Revised Amended 8-4-2008

TABLE 23A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation: Automatic Input from Sch 1A				17,305,948	1,910,989	4,332,258	11,062,701
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST		30,240	-	-	30,240
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD			-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST		36,126,975	-	-	36,126,975
Common Plant	356 & 356.1		DIRECT					
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST		-	-	-
Total					**$ 36,157,215**	**$ -**	**$ -**	**$ 36,157,215**
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST		-	-	-
Other Investment	110-111	124	DIST		6,991,860	-	-	6,991,860
Long-Term Portion of Derivative Assets	110-111	175	DIST			-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST			-	-	-
Total					**$ 6,991,860**	**$ -**	**$ -**	**$ 6,991,860**
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD			-	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD			-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD		10,566,630	3,140,214	793,277	6,633,139
Merchandise (Major Only)	110-112	155	DIST			-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST			-	-	-
EPA Allowance Inventory	110-112	158.1	PROD			-	-	-
EPA Allowances Withheld	110-112	158.2	PROD			-	-	-
Stores Expense Undistributed	110-111	163	PTD		(130,948)	(38,915)	(9,831)	(82,202)
Prepayments	110-111	165	PTD		823,633	244,769	61,833	517,031
Derivative Instrument Assets	110-111	175	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST			-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST			-	-	-
Total					**$ 11,259,315**	**$ 3,346,067**	**$ 845,279**	**$ 7,067,968**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Snohomish	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	6/30/2008	Revised Amended 8-4-2008

TABLE 23A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG		7,323,374	2,062,125	606,396	4,654,853
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST		-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST		-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST		-	-	-
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST			-	-	-
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST		25,991	-	-	25,991
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST			-	-	-
Clearing Accounts	110-111	184	DIST			-	-	-
Temporary Facilities	110-111	185	PTDG			-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST	301,790,572	183,024,339	-	118,766,233
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT					
Research, Development, and Demonstration Expenditures	110-111	188	DIST			-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG		36,415,208	10,253,839	3,015,283	23,146,086
Accumulated Deferred Income Taxes	110-111	190	DIST			-	-	-
Total					**$ 345,555,145**	**$ 195,340,302**	**$ 3,621,679**	**$ 146,593,164**
Total Assets and Other Debits					**$ 417,269,483**	**$ 200,597,359**	**$ 8,799,217**	**$ 207,872,908**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
Proposed 2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	Snohomish	
End of Year Report Period:	2006	Amended 7-8-2008
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TABLE 23A: Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Liabilities and Other Credits (Comparative Balance Sheet)								
CURRENT AND ACCRUED LIABILITIES								
Derivative Instrument Liabilities	112-113	244	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST			-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST			-	-	-
Total					**$ -**	**$ -**	**$ -**	**$ -**
DEFERRED CREDITS								
Customer Advances for Construction	112-113	252	DIST			-	-	-
Other Deferred Credits	112-113	253	DIRECT	DIST	294,401,421	153,744,980	-	140,656,441
Other Regulatory Liabilities	112-113	254	DIST	DIST		-	-	-
Accumulated Deferred Investment Tax Credits	112-113	255	DIST			-	-	-
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT					
Unamortized Gain on Reacquired Debt	112-113	257	PTDG			-	-	-
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST			-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST			-	-	-
Accumulated Deferred Income Taxes-Other	112-113	283	DIST			-	-	-
Total					**$ 294,401,421**	**$ 153,744,980**	**$ -**	**$ 140,656,441**
Total Liabilities and Other Credits					**$ 294,401,421**	**$ 153,744,980**	**$ -**	**$ 140,656,441**
Total Rate Base					**$ 965,280,470**	**$ 274,834,335**	**$ 80,717,366**	**$ 609,728,677**

Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Snohomish	
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TABLE 23B: Schedule 1A: Cash Working Capital (f)

(Automatic Input from Schedule 3- Expenses)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	304,841,082	302,675,460	-	2,165,622
Total Transmission O&M (i)	33,413,258	-	33,413,258	-
Total Distribution O&M	43,259,298	-	-	43,259,298
Total Customer & Sales	17,002,751	-	-	17,002,751
Total Administrative and General O&M	34,821,743	5,337,380	1,244,805	28,239,558
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	294,890,547	292,724,925	-	2,165,622
Revised Total O&M Expenses	**$ 138,447,585**	**$ 15,287,915**	**$ 34,658,063**	**$ 88,501,607**
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	**$ 17,305,948**	**$ 1,910,989**	**$ 4,332,258**	**$ 11,062,701**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Snohomish	
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TABLE 23C: Schedule 2: Capital Structure and Rate of Return (b)

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:	5.220%
Multi-Jurisdiction Investor-Owned Utility Return Calculation:	
Consumer-Owned Utility Return Calculation:	
Rate of Return :	**5.220%**

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order

Note: Multi-jurisdictional utilities must begin on Page 2
Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**
Debt	$ 621,380,316.8	100.0%	5.22%	5.220%
Preferred Equity				
Common Equity				
Weighted Cost of Capital	**$ 621,380,316.8**	**100.000%**		**5.220%**

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) **35%**

Federal Income Tax Factor

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}* 4213446.492

Federal Income Tax Adjusted Weighted Cost of Capital **5.220%**

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 965,280,470	$ 274,834,335	$ 80,717,366	$ 609,728,677
Federal Income Tax Adjusted Weighted Cost of Capital	5.220%	5.220%	5.220%	5.220%
Federal Income Tax Adjusted Return on Rate Base	**$50,387,641**	**$14,346,352**	**$4,213,446**	**$31,827,837**

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

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TABLE 23C: Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation

Step 1:

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 1

	Capitalization Structure		Effective Cost		Jurisdictional	Effective Cost -	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**	**Allocation**	**Weighted**	**State Allocation**
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 2

Component	Amount	Percent	Embedded	Weighted			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 3

Component	Amount	Percent	Embedded	Weighted			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Jurisdiction	Rate Base	Weighted cost	%	Weighted Return		
Total						

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

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TABLE 23C: Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation *(continued)*

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	**35%**
Federal Income Tax Factor	

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 965,280,470	$ 274,834,335	$ 80,717,366	$ 609,728,677
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Snohomish	
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TABLE 23C: Schedule 2: Capital Structure and Rate of Return (b)

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

Debt Issue	Original Amount	Year Issued	Year Due	Interest Rate	Interest Expense
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	$ -				$ -

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ 965,280,470	$ 274,834,335	$ 80,717,366	$ 609,728,677
Weighted Cost of Debt				
Return on Rate Base				

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Snohomish	
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TABLE 23D: Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD		889,657	889,657	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD			-	-	-
Steam Power - Maintenance	320-323	510-515	PROD			-	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD			-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD			-	-	-
Nuclear - Maintenance	320-323	528-532	PROD			-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD		951,172	951,172	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD		964,879	964,879	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD			-	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD			-	-	-
Other Power - Maintenance	320-323	551-554.1	PROD			-	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	320-323	555	PROD		286,782,149	286,782,149	-	-
System Control and Load Dispatching	320-323	556	PROD			-	-	-
Other Expenses	320-323	557	PROD		8,034,484	8,034,484	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (h)			DIRECT		7,218,741	5,053,119	-	2,165,622
Total Production Expense					**$ 304,841,082**	**$ 302,675,460**	**$ -**	**$ 2,165,622**
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS		31,991,881	-	31,991,881	-
Total Operations less Wheeling	320-323	560-567.1	TRANS		130,398	-	130,398	-
Total Maintenance	320-323	568-574	TRANS		1,290,979	-	1,290,979	-
Total Transmission Expense					**$ 33,413,258**	**$ -**	**$ 33,413,258**	**$ -**

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Proposed 2008 Average System Cost Methodology

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TABLE 23D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Distribution Expense:								
Total Operations	320-323	580-589	DIST		16,944,031	-	-	16,944,031
Total Maintenance	320-323	590-598	DIST		26,315,267	-	-	26,315,267
Total Distribution Expense					$ 43,259,298	$ -	$ -	$ 43,259,298
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST		14,843,491	-	-	14,843,491
Customer Service and Information	320-323	906-907	DIST		1,530,444	-	-	1,530,444
Customer Assistance Expenses (Major only)	320-323	908	DIRECT			-	-	-
Customer Service and Information	320-323	909-910	DIST			-	-	-
Total Sales Expense	320-323	911-917	DIST		628,816	-	-	628,816
Total Customer and Sales Expenses					$ 17,002,751	$ -	$ -	$ 17,002,751
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR		17,605,470	2,411,278	540,349	14,653,843
Office Supplies & Expenses	320-323	921	LABOR		4,775,798	654,102	146,579	3,975,116
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR		7,945,131	1,088,180	243,853	6,613,098
Outside Services Employed	320-323	923	LABOR		8,996,954	1,232,240	276,136	7,488,579
Property Insurance	320-323	924	PTDG		709,007	199,643	58,708	450,656
Injuries and Damages	320-323	925	LABOR		2,487,605	340,707	76,350	2,070,548
Employee Pensions & Benefits	320-323	926	LABOR		2,241,341	306,978	68,792	1,865,571
Franchise Requirements	320-323	927	DIST			-	-	-
Regulatory Commission Expenses	320-323	928	DIST			-	-	-
(Less) Duplicate Charges - Credit	320-323	929	PTDG			-	-	-
General Advertising Expenses	320-323	930.1	DIST	DIST	1,218,955	-	-	1,218,955
Miscellaneous General Expenses	320-323	930.2	DIST			-	-	-
Rents	320-323	931	DIST		179,472	-	-	179,472
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM		4,552,272	1,280,612	321,745	2,949,915
Total Administration and General Expenses					$ 34,821,743	$ 5,337,380	$ 1,244,805	$ 28,239,558

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

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TABLE 23D: Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Total Operations and Maintenance					$ 433,338,132	$ 308,012,840	$ 34,658,063	$ 90,667,229
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	PTD	PTD	60	18	5	38
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST	4,804,579	-	294,480	4,510,099
Steam Production Plant	336	403	PROD			-	-	-
Nuclear Production Plant	336	403	PROD			-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD			-	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD			-	-	-
Other Production Plant	336	403	PROD		8,552,943	8,552,943	-	-
Transmission Plant (i)	336	403	TRANS		2,286,691	-	2,286,691	-
Distribution Plant	336	403	DIST		21,656,689	-	-	21,656,689
General Plant	336	403	GP		5,948,933	1,414,886	456,182	4,077,866
Common Plant - Electric	336	403	DIRECT					
Common Plant - Electric	336	404	DIRECT					
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT					
Amortization of Limited Term Electric Plant	336	404	DIRECT					
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIRECT					
Total Depreciation and Amortization					$ 43,249,895	$ 9,967,847	$ 3,037,357	$ 30,244,691
Total Operating Expenses					$ 476,588,027	$ 317,980,686	$ 37,695,420	$ 120,911,920
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

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TABLE 23E: Schedule 3A Items: Taxes (Including Income Taxes)

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Funct. Method	Total	Production	Transmission	Distribution/ Other
FEDERAL							
Income Tax (Included on Schedule 2)	262	409.1	DIST		-	-	-
Employment Tax	262	408.1	LABOR		-	-	-
Other Federal Taxes	262	408.1	DIST		-	-	-
TOTAL FEDERAL				$ -	$ -	$ -	$ -
STATE AND OTHER							
Property	262	408.1	PTDG		-	-	-
Unemployment	262	408.1	LABOR		-	-	-
State Income, B&O, et.	262	409.1	DIST		-	-	-
Franchise Fees	262	408.1	DIST		-	-	-
Regulatory Commission	262	408.1	DIST		-	-	-
City/Municipal	262	408.1	DIST		-	-	-
Other	262	408.1	DIST	27,327,579	-	-	27,327,579
TOTAL STATE AND OTHER TAXES				$ 27,327,579	$ -	$ -	$ 27,327,579
TOTAL TAXES				$ 27,327,579	$ -	$ -	$ 27,327,579

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TABLE 23F: Schedule 3B Other Included Items

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD		-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST		-	-	-
Gain from Disposition of Utility Plant	114	411.6	DIRECT	PROD		-	-	-
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST		-	-	-
Gain from Disposition of Allowances	114	411.8	PROD			-	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD			-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD		-	-	-
Total Other Included Items					$ -	$ -	$ -	$ -
Sales for Resale:								
Sales for Resale	310	447	PROD		105,466,684	105,466,684	-	-
Total Sales for Resale					$ 105,466,684	$ 105,466,684	$ -	$ -
Other Revenues:								
Forfeited Discounts	300	450	DIST			-	-	-
Miscellaneous Service Revenues	300	451	DIST		2,663,587	-	-	2,663,587
Sales of Water and Water Power	300	453	PROD			-	-	-
Rent from Electric Property	300	454	TD		1,852,350	-	197,865	1,654,485
Interdepartmental Rents	300	455	DIST			-	-	-
Other Electric Revenues	300	456	DIRECT	PROD	30,457,911	-	237,899	30,220,012
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS		5,562,380	-	5,562,380	-
Total Other Revenues					$ 40,536,228	$ -	$ 5,998,144	$ 34,538,084
Total Other Included Items					$ 146,002,912	$ 105,466,684	$ 5,998,144	$ 34,538,084

(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Snohomish	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	6/30/2008	Revised Amended 8-4-2008

TABLE 23G: Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses	$ 476,588,027	$ 317,980,686	$ 37,695,420	$ 120,911,920
(From Schedule 3)				
Federal Income Tax Adjusted Return on Rate Base	$ 50,387,641	$ 14,346,352	$ 4,213,446	$ 31,827,837
(From Schedule 2)				
State and Other Taxes	$ 27,327,579	$ -	$ -	$ 27,327,579
(From Schedule 3a)				
Total Other Included Items	$ 146,002,912	$ 105,466,684	$ 5,998,144	$ 34,538,084
(From Schedule 3b)				
Total Cost	**$ 408,300,335**	**$ 226,860,355**	**$ 35,910,723**	**$ 145,529,252**

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Snohomish	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	6/30/2008	Revised Amended 8-4-2008

TABLE 23G: Schedule 4: Average System Cost

Contract System Cost	
Production	$ 226,860,355
Transmission	$ 35,910,723
(Less) New Large Single Load Costs (d)	
Total Contract System Cost	**$ 262,771,078**
Contract System Load (MWh)	
Total Retail Load	6,480,261
(Less) New Large Single Load	
Total Retail Load (Net of NLSL) (d)	6,480,261
Distribution Loss (f)	324,013
Total Contract System Load	**6,804,274**
Average System Cost $/MWh	**38.62**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Snohomish	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	6/30/2008	Revised Amended 8-4-2008

TABLE 23H: Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	2,080,871
Transmission	354-355	21,234
Distribution	354-355	11,758,560
Customer Accounts	354-355	9,165,065
Customer Service and Information	354-355	3,458,773
Sales	354-355	85,689
Administrative and General	354-355	19,166,538
TOTAL Operation		**$45,736,730**
Maintenance		
Production	354-355	
Transmission	354-355	282,589
Distribution	354-355	10,761,620
Administrative and General	354-355	
TOTAL Maintenance		**$11,044,209**
Operation and Maintenance		
Production (Enter Total of lines 1 and 9)	354-355	2,080,871
Transmission (Enter Total of lines 2 and 10)	354-355	303,823
Distribution (Enter Total of lines 3 and 11)	354-355	22,520,180
Customer Accounts (Transcribe from line 4)	354-355	9,165,065
Customer Service and Information (Transcribe from line 5)	354-355	3,458,773
Sales (Transcribe from line 6)	354-355	85,689
Administrative and General (Enter Total of lines 7 and 12)	354-355	19,166,538
TOTAL Operation and Maintenance		**$56,780,939**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Snohomish
End of Year Report Period:	2006
ASC Filing Date:	6/30/2008

Amended 7-8-2008
Revised Amended 8-4-2008

TABLE 23I*: *Ratio Table

Labor Ratio Input:	Ratio Used	Total	Production	Transmission	Distribution
Production	PROD	$ 2,080,871	$ 2,080,871	$ -	$ -
Transmission	TRANS	303,823	-	303,823	-
Distribution	DIST	22,520,180	-	-	22,520,180
Customer Accounts	DIST	9,165,065	-	-	9,165,065
Customer Service and Informational	DIRECT	3,458,773	-	-	3,458,773
Sales	DIST	85,689	-	-	85,689
Administrative & General	PTD	19,166,538	5,695,953	1,438,905	12,031,681
Total Labor		$ 56,780,939	$ 7,776,824	$ 1,742,728	$ 47,261,388
LABOR RATIO		**100%**	**14%**	**3%**	**83%**

GP General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
Land and Land Rights	PTD	$ 2,885,820	$ 857,614	$ 216,649	$ 1,811,556
Structures and Improvements	PTD	60,594,190	18,007,510	4,549,035	38,037,644
Furniture and Equipment	LABOR	10,268,103	1,406,339	315,150	8,546,615
Transportation Equipment	TD	20,302,164	-	2,168,642	18,133,522
Stores Equipment	PTD	862,334	256,270	64,739	541,325
Tools and Garage Equipment	PTD	2,719,250	808,112	204,144	1,706,993
Laboratory Equipment	PTD	2,244,491	667,023	168,502	1,408,966
Power Operated Equipment	TD	820,827	-	87,679	733,148
Communication Equipment	PTD	32,740,851	9,729,996	2,457,980	20,552,876
Miscellaneous Equipment	PTD	64,873	19,279	4,870	40,724
Other Tangible Property	DIRECT	-	-	-	-
Asset Retirement Costs for General Plant	PTD	-	-	-	-
TOTAL		$ 133,502,903	$ 31,752,143	$ 10,237,392	$ 91,513,368
GP RATIO		**100%**	**24%**	**8%**	**69%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	Snohomish	
End of Year Report Period:	2006	Amended 7-8-2008
ASC Filing Date:	6/30/2008	Revised Amended 8-4-2008

TABLE 23I: Ratio Table

PTD — **Production, Transmission, Distribution Ratio**

	Ratio Used	Total	Production	Transmission	Distribution
Steam Production	PROD	$ 132,438,035	$ 132,438,035	$ -	$ -
Nuclear Production	PROD	-	-	-	-
Hydraulic Production	PROD	208,007,068	208,007,068	-	-
Other Production	PROD	-	-	-	-
Total Production Plant		340,445,103	340,445,103	-	-
Transmission Plant	TRANS	86,002,829	-	86,002,829	-
Total Distribution Plant	DIST	719,129,388	-	-	719,129,388
TOTAL		$ 1,145,577,320	$ 340,445,103	$ 86,002,829	$ 719,129,388
PTD RATIO		**100%**	**30%**	**8%**	**63%**

PTDG — **Production, Transmission, Distribution and General Plant Ratio**

	Ratio Used	Total	Production	Transmission	Distribution
PTD Total		$ 1,145,577,320	$ 340,445,103	$ 86,002,829	$ 719,129,388
Intangible Plant - Organization	DIST	-	-	-	-
Intangible Plant - Franchises and Consents	DIRECT	3,009	-	-	3,009
Intangible Plant - Miscellaneous	DIRECT	61,978,198	5,420,464	14,803,486	41,754,247
General Plant Total		133,502,903	31,752,143	10,237,392	91,513,368
TOTAL		$ 1,341,061,430	$ 377,617,710	$ 111,043,707	$ 852,400,012
PTDG RATIO		**100%**	**28%**	**8%**	**64%**

TD — **Transmission and Distribution Plant Ratio**

	Ratio Used	Total	Production	Transmission	Distribution
Total Transmission Plant	TRANS	$ 86,002,829	$ -	$ 86,002,829	$ -
Total Distribution Plant	DIST	719,129,388	-	-	719,129,388
TOTAL		$ 805,132,217	$ -	$ 86,002,829	$ 719,129,388
TD RATIO		**100%**	**0%**	**11%**	**89%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

UTILITY NAME:	**Snohomish**	
End of Year Report Period:	**2006**	**Amended 7-8-2008**
ASC Filing Date:	**6/30/2008**	**Revised Amended 8-4-2008**

TABLE 23I: Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
GPM	**Maintenance of General Plant Ratio**					
	Structures and Improvements	PTD	$ 60,594,190	$ 18,007,510	$ 4,549,035	$ 38,037,644
	Furniture and Equipment	LABOR	10,268,103	1,406,339	315,150	8,546,615
	Communication Equipment	PTD	32,740,851	9,729,996	2,457,980	20,552,876
	Miscellaneous Equipment	PTD	64,873	19,279	4,870	40,724
	TOTAL		$ 103,668,017	$ 29,163,124	$ 7,327,035	$ 67,177,858
	GPM RATIO		**100%**	**28%**	**7%**	**65%**

SUMMARY RATIO TABLE

Direct to Distribution	**DIST**	**0.00%**	**0.00%**	**100.00%**
Direct to Production	**PROD**	**100.00%**	**0.00%**	**0.00%**
Direct to Transmission	**TRANS**	**0.00%**	**100.00%**	**0.00%**
Direct Allocation	**DIRECT**	**0.00%**	**0.00%**	**0.00%**
General Plant	**GP**	**23.78%**	**7.67%**	**68.55%**
Maintenance of General Plant	**GPM**	**28.13%**	**7.07%**	**64.80%**
Labor Ratios	**LABOR**	**13.70%**	**3.07%**	**83.23%**
Production, Transmission, Distribution	**PTD**	**29.72%**	**7.51%**	**62.77%**
Production, Transmission, Distribution, General	**PTDG**	**28.16%**	**8.28%**	**63.56%**
Transmission, Distribution	**TD**	**0.00%**	**10.68%**	**89.32%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Proposed 2008 Average System Cost Methodology

TABLE 23J UTILITY NAME: **Snohomish**

End of Year Report Period: **2006** **Amended 7-8-2008**

ASC Filing Date: **6/30/2008** **Revised Amended 8-4-2008**

Purchased Power & Off-System Sales

FERC Form 1		Purchased Power		
Statistical Classification	Page Number	Settlement Total		MWh Purchased
RQ	326-327			
LF	326-327	$	242,230,460	8,395,056
IF	326-327			
SF	326-327	$	44,551,689	852,109
LU	326-327			
IU	326-327			
OS	326-327			
EX	326-327			
NA	326-327			
AD	326-327			
TOTAL		**$**	**286,782,149**	**9,247,165**

FERC Form 1		Sales for Resale		
Statistical Classification	Page Number	Settlement Total		MWh Purchased
RQ	310-311			
LF	310-311			
IF	310-311			
SF	310-311			
LU	310-311			
IU	310-311			
OS	310-311	$	105,466,684	2,105,474
EX	310-311			
NA	310-311			
AD	310-311			
TOTAL		**$**	**105,466,684**	**2,105,474**

SNOPUD **TABLE 23K: Forecasted Contract System Costs & ASC with New Additions and NLSL**

Date	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
	6	7	8	9	10
Fiscal Year	2009	2010	2011	2012	2013
Rate Period Mid-Point	**TRUE**	**FALSE**	**FALSE**	**FALSE**	**FALSE**
Contract System Cost					
Production	239,609,815	254,546,263	257,833,058	274,327,600	277,644,989
Transmission	37,780,520	38,148,568	38,641,922	39,188,191	39,772,181
NLSL Fully Allocated Cost ($/MWh)					
(Less) New Large Single Load Costs (d)	**0**	**0**	**0**	**0**	**0**
Total Contract System Cost	277,390,335	292,694,831	296,474,980	313,515,790	317,417,170
Contract System Load (MWh)					
Total Retail Load @ Meter	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
(Less) New Large Single Load	**0**	**0**	**0**	**0**	**0**
Total Retail Load (Net of NLSL) (d)	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
Distribution Loss (f)	346,873	351,704	354,636	357,506	360,114
Total Contract System Load	7,284,334	7,385,777	7,447,346	7,507,618	7,562,386
Average System Cost $/MWh	**38.08**	**39.63**	**39.81**	**41.76**	**41.97**

	Rate Period Mid-Point
Date	**4/1/09**
Fiscal Year	2009
NLSL Switch	0
Contract System Cost	
Production	239,609,815
Transmission	37,780,520
(Less) New Large Single Load Costs (d)	0
Total Contract System Cost	277,390,335
Contract System Load (MWh)	
Total Retail Load @ Meter	6,937,461
(Less) New Large Single Load	**0**
Total Retail Load (Net of NLSL) (d)	6,937,461
Distribution Loss (f)	346,873
Total Contract System Load	7,284,334
Average System Cost $/MWh	**38.08**

Table 24
Average System Cost Forecast for 7(b)(2) Rate Test
(Dollars per megawatthour)

				FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Avista				50.28	48.42	48.69	48.47	48.41
Centralia				35.56	36.71	36.68	38.27	38.26
Franklin				45.74	47.59	47.24	50.01	49.62
Idaho				33.86	33.96	34.34	34.6	34.99
Northwestern				54.84	55.36	56.06	56.85	57.72
	10/1/2008	1/1/2009	6/1/2009					
PacifiCorp	50.4	51.34	51.82	51.27	49.68	49.47	48.95	48.56
	10/1/2008	4/1/2009	8/1/2009					
PGE	54.99	55.59	57.53	55.61	56.01	56.43	56.43	56.59
PSE				59.71	59.72	60.36	60.92	61.56
Snohomish				38.08	39.63	39.81	41.76	41.97

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WP-07 SUPPLEMENTAL WHOLESALE
POWER RATE ADJUSTMENT PROCEEDING

FY 2009 AVERGE SYSTEM COST REPORTS

- Avista
- Centralia City Light
- Franklin County PUD
- Idaho Power
- NorthWestern
- PacifiCorp
- Portland General Electric
- Puget Sound Energy
- Snohomish County PUD

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FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

AVISTA UTILITIES

Docket Number: AV-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

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TABLE OF CONTENTS

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I. FILING DATA

Utility	Parties to the Filing
Avista Utilities 1411 E. Mission Spokane, WA 99202	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept.11, 2008 Final
Production Cost	$367,559,241	$367,368,078	$367,368,078	$367,663,808
Transmission Cost	$61,061,647	$60,812,647	$61,000,640	$61,000,640
(Less) New Large Single Load Costs	$0	$35,902,963	$4,204,341	$4,205,570
Total Contract System Cost	$428,620,888	$392,277,762	$424,164,378	$424,458,879
Total Retail Load (MWh)	8,787,002	8,787,002	8,787,002	8,787,002
(Less) New Large Single Load	0	551,335	61,449	61,449
Total Retail Load (Net NLSL)	8,787,002	8,235,667	8,725,553	8,725,553
Plus Distribution Losses	439,350	460,439	460,439	460,439
Total Contract System Load (MWh)	9,226,352	8,696,105	9,185,992	9,185,992
FY 2006 Base Period ASC ($/MWh)	**46.46**	**45.11**	**46.18**	**46.21**

B. FY 2009 (Exchange Period) ASC without New Resource Additions ($/MWh)

		July 8, 2008 As Amended	August 4, 2008 As Revised	Sept.11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**N/A**	**47.83**	**48.84**	**50.28**

C. FY 2009 (Exchange Period) ASC with New Resource Additions ($/MWh)

FY 2007-2009 New Resource Additions - See Table1in Section III.B for details: N/A
There are no New Resource Additions recorded that met the 2.5 percent materiality threshold.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging Utilities agreed to a number of termination agreements that provided for payments to each Utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the

REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing Utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. <u>ASC Determination Process Guidelines and Expedited Review Process</u>

The purpose of BPA's expedited review process is to estimate exchanging Utilities' ASCs for FY 2009 that could be incorporated into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding rely on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance to the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1.

The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a Base Period ASC determination, BPA used the ASC Forecast model, an Excel-based spreadsheet, to escalate the Base Period ASC forward to the effective rate period, FY 2009 (October 1, 2008 through September 30, 2009). The Base Period and Forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1 to determine the Utility's return on investment.

IOUs use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For Consumer-Owned Utilities (COU), the rate of return is equal to the COU’s weighted cost of debt times total rate base.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as outlined in the ASCM, Table 1. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as “combined” line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items. The schedule also lists the load information, as defined below, and calculates the Utility's ASC.

Contract System Cost:
The Contract System Cost is the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Load:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any New Large Single Load(s) (NLSL).

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Sales for Resale

The Purchased Power is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1, pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A NLSL is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro rata basis using salary and wage data for Production, Transmission, and Distribution/other functions included in the Utility's most recently filed Form 1. For COUs, comparable data is used based on the cost of service analysis (COSA) study used as the basis for retail rates in effect during the Base Year filing.

D. ASC Forecast

The Base Period ASC is applied to an Excel-based forecasting model to escalate the Base Year ASC data forward to the Exchange Period. For purposes of the expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Cost

Forecast Contract System Cost (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5 percent. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of any major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING AND RESPONSE TO COMMENTS

A. Identification and Analysis of Issues from the May 7, 2008, ASC Appendix 1 Filing

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Cost and Contract System Load filed on May 7, 2008 by Avista, and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below. Minor changes may have occurred due to a functionalization ratio percentage allocation or rounding. If such minor changes occurred and they did not affect the overall ASC, the changes were not addressed in this report.

SCHEDULE 1: Plant Investment/Rate Base

1. **Account 303,** Intangible Plant Miscellaneous: incorrect functionalization

   a. Statement of Issue: In the May 7 filing, Avista directly assigned the transmission portion of this account, and allocated the computer software in this account using Avista's PTD ratio.

   b. Statement of Facts: The proposed ASCM permits Direct Analysis only for specified accounts. The ASCM contains default functionalization methods in the absence of Direct Analysis where appropriate. BPA does not allow Utilities to use a combination of direct analysis and a prescribed functionalization method for the same account. However, Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility, through direct analysis, can justify how the ratio adequately reflects the functional nature of the costs included in any account or cost item being functionalized by the ratio.

   c. Analysis of Position and Decision: At the time of Avista's initial May 7, 2008, Appendix 1 filings, BPA did not allow a Utility to combine a direct analysis with a prescribed functionalization method for the same account under any circumstance. Therefore, Avista's allocation of PTD to the computer software was considered incorrect and Avista was not allowed to revise the allocation in time to provide a Direct Analysis. For this reason, BPA re-allocated account 303 in its entirety to Distribution/Other.

   In the ASCM ROD, BPA clarified its treatment of Account 303. For the final Methodology, Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility, through Direct Analysis, can justify how the ratio adequately reflects the functional nature of the costs included in any account or cost item being functionalized by the ratio." (2008 ASCM Final Record of Decision at 30). Until additional supporting data are submitted, BPA will continue to functionalize Account 303, Intangible Plant Miscellaneous, in its entirety to Distribution/Other.

2. **Account 186**, Miscellaneous Deferred Debits: incorrect functionalization of line item "WA Deferred Power Costs"

   a. Statement of Issue: In its May 7 filing, Avista functionalized WA Deferred Power Costs to Distribution/Other. This "Wa Deferred Power Costs" line item appears to be a Power debit, not a Distribution/Other debit.

b. Statement of Facts: Avista functionalized this Account to Distribution/ Other without providing supporting documentation for the debit account. In its analysis, Avista did not comment on line items that were deemed immaterial, were assigned to Distribution, or were unduly burdensome to provide details.

c. Analysis of Position and Decision: This Account falls under Deferred Debits. Because Avista did not include supporting documentation, BPA functionalized the WA Deferred Power Cost debit to Production.

3. **Account 186**, Miscellaneous Deferred Debits: incorrect functionalization of line item "Regulatory Assets Conservation"

a. Statement of Issue: In its May 7 filing, Avista functionalized Regulatory Assets Conservation to DIR-C Ratio.

b. Statement of Facts: BPA no longer recognizes DIR-C as a valid functionalization ratio. BPA no longer uses ratios to functionalize conservation program costs or revenues. BPA examines conservation program costs on a utility-by-utility basis. Utilities are allowed to functionalize all conservation related costs to production, irrespective of the functionalization rules specified for the account. The balance of the costs included in such accounts shall be functionalized according to the functionalization rules specified for the account.

c. Analysis of Position and Decision: At the time of Avista's initial May 7, 2008, Appendix 1 filings, BPA allowed a Utility to use the conservation ratio (DIR-C) at an allocation of 70% Production and 30% Distribution for conservation line items when appropriate. Since the May filing and publication of the draft ROD, BPA has revised its treatment of conservation issues (see the Final ASCM for details) and now allows Direct Analysis to functionalize conservation measures to Production if the Utility can justify the allocation. For purposes of this report, BPA re-functionalized Regulatory Assets Conservation to Direct Analysis but continued to allocate the costs 70% to Production and 30% to Distribution. BPA will allow Avista to submit documentation for this line item and correct the functionalization as appropriate. If Avista does not submit appropriate documentation, BPA will functionalize "Regulatory Assets Conservation" to Distribution/Other.

4. **Accounts 244 and 245**: Current and Accrued Liabilities Long-Term Portions of Derivative Instrument Liabilities" and Deferred Credits "Long-Term Portions of Derivative Instrument Liabilities-Hedges"

a. Statement of Issue: The May 7 filing Appendix 1 template inadvertently added lines items *Long-Term Portions of Derivative Instrument Liabilities and Long-Term Portions of Derivative Instrument Liabilities-Hedges* twice; once in Current and Accrued Liabilities and once in Deferred Credits. Avista inadvertently entered data in both areas.

b. Statement of Facts: The additional line items were in error and BPA has since removed them from Deferred Credits.

c. Analysis of Position and Decision: BPA's deletion of the two additional line items, $10,174,378 for the Long-Term Portions of Derivative Instrument Liabilities and $5,144,457 for the Long-Term Portions of Derivative Instrument Liabilities-Hedges, did not cause a change to Avista's Total Liabilities and Other Credits.

5. **Account 253**, Other Deferred Credits: incorrect functionalization of line item "BPA C&RD Receipts (253100)"

a. Statement of Issue: In its May 7 filing, Avista functionalized BPA C&RD Receipts (253100) to DIR-C Ratio. C&RD is a conservation measure.

b. Statement of Facts: BPA no longer recognizes DIR-C as a valid functionalization ratio.

c. Analysis of Position and Decision: At the time of Avista's initial May 7, 2008, Appendix 1 filing, BPA allowed a Utility to use the conservation ratio (DIR-C) at an allocation of 70% Production and 30% Distribution for conservation line items when appropriate. Since the May filing and publication of the draft ROD, BPA has revised its treatment of conservation issues (see the Final ASCM for details) and now allows Direct Analysis to functionalize conservation measures to Production if the Utility can justify the allocation. For purposes of this report, BPA re-functionalized BPA C&RD Receipts to Direct Analysis but continued to allocate the costs 70% to Production and 30% to Distribution. BPA will allow Avista to submit documentation for this line item and correct the functionalization as appropriate. If Avista does not submit appropriate documentation, BPA will functionalize "BPA C&RD Receipts (253100)" to Distribution/Other.

SCHEDULE 1A: Cash Working Capital – no changes from the May 7 filing

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the May 7 filing

SCHEDULE 3: Expenses- no changes from the May 7 filing

SCHEDULE 3A: Taxes – no changes from the May 7 filing

SCHEDULE 3B: Other Included Items – no changes from the May 7 filing

SCHEDULE 4: Average System Cost

1. **Distribution Loss**:

   a. Statement of Issue: In its filing, Avista used a 5 percent Distribution Loss Factor to determine its ASC.

   b. Statement of Facts: The May 7 filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years.

   Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

   c. Analysis of Position and Decision: For purposes of this expedited filing, BPA completed the Distribution Loss Factor calculation outlined in the ASCM ROD, Section 4.10.5. A distribution loss factor of 5.24 percent was used.

2. **Contract System Load:** New Large Single Load (NLSL)

   a. Statement of Issue: The May 7 Appendix 1 filing did not require and therefore did not include information on NLSL MWh. BPA now requires that such data be included in the determination of a Utility's ASC.

   b. Statement of Facts: Avista submitted data identifying one potential NLSL usage of 551,335 MWh. BPA determined this load by the evaluation of Avista provided data.

c. Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit costs of servicing an NLSL to be included in the calculation of a Utility's ASC and, therefore, BPA removed the potential NLSL and associated costs from the Appendix 1 amended filing. The results are noted in Schedule 4 of the amended Appendix 1 filing.

3. **Contract System Cost:** New Large Single Load (NLSL) Costs

   a. Statement of Issue: The May 7 filing Appendix 1 template did not require and therefore did not include information on NLSL costs. BPA now requires this data to be included in the determination of a Utility's ASCs.

   b. Statement of Facts: BPA determined the cost of serving the potential NLSL using the fully allocated cost of all escalated base period post-September 1, 1979, resources and major resource additions and long-term power purchases (5 years or longer contracts) used to determine Exchange Period ASCs as outlined in the ASCM ROD, section 4.5.

   c. Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit costs of servicing an NLSL to be included in the calculations of a Utility's ASC and therefore, BPA removed the NLSL and associated costs from the Appendix 1 amended filing. The results are noted in Schedule 4 of the amended Appendix 1 filing and in Table 2 at the end of this report. In addition, BPA will publish the resource cost determinations to NLSL work papers at the ASCM web site: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – no changes from the May 7 filing

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes from the May 7 filing

SUPPORTING DOCUMENTATION: Labor Ratios from the May 7 filing

1. **Maintenance of General Plant (GPM) Ratio:** Miscellaneous Equipment

   a. Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

   b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

c. Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

B. Identification and Analysis of Issues based on Comments to the July 8, Draft ASC Report

SCHEDULE 1: Plant Investment/Rate Base

1. **Account 303**, Intangible Plant Miscellaneous: Incorrect functionalization.

a. **Analysis of Position and Decision:** At the time of Avista's initial May 7, 2008, Appendix 1 filings, BPA did not allow a Utility to combine a Direct Analysis with a prescribed functionalization method for the same account under any circumstance. Therefore, Avista's allocation to PTD of the computer software was considered incorrect and Avista was not allowed to revise the allocation in time to provide a Direct Analysis. For this reason, BPA re-allocated account 303 in its entirety to Distribution/Other.

In its Record of Decision (ROD) for the Average System Cost Methodology, BPA clarified its treatment for the final Methodology for Account 303, as follows: utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the utility, through Direct Analysis, can justify how the ratio adequately reflects the functional nature of the costs included in any account or cost item being functionalized by the ratio." (2008 ASCM Final Record of Decision at 30). Until additional supporting data are submitted, BPA will continue to functionalize Account 303, Intangible Plant Miscellaneous, in its entirety, to Distribution/Other.

b. **Avista Comments on Decision:** The proposed ASCM permits Direct analysis for this account. Since Avista has directly analyzed the transmission portion of this account, and has provided appropriate support, we advocate this portion be moved from Distribution/Other, and placed back into Transmission ($1,517,348). Avista understands it will need to directly assign the remaining portions of software that were originally assigned to PTD before the October 1st submission. Over the next couple months, Avista will assess whether directly assigning these costs is feasible or is simply too burdensome to be reasonably accomplished.

c. **BPA Response to Avista's Comment:** BPA agrees with Avista in the allocation of $1,517,348 in transmission costs and has functionalized this amount to Transmission. This change is reflected in the Revised Amended Appendix 1 dated August 4, 2008.

SCHEDULE 1A: Cash Working Capital – no changes from the May 7 filing

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the May 7 filing

SCHEDULE 3: Expenses- no changes from the May 7 filing

SCHEDULE 3A: Taxes – no changes from the May 7 filing

SCHEDULE 3B: Other Included Items – no changes from the May 7 filing

SCHEDULE 4: Average System Cost

1. **Contract System Load:** New Large Single Load (NLSL)

    a. **Analysis of Position and Decision:** Section 5 (c) of the Northwest Power Act does not permit costs of servicing a NLSL to be included in the calculation of a Utility's ASC, and therefore, BPA removed the potential NLSL and associated costs from the Appendix 1 amended filing. The results are noted in Schedule 4 of the amended Appendix 1 filing.

    b. **Avista's Comment on Decision:** [Avista submitted to BPA] "Informal Request for Consideration of the Determination of the Potlatch Lewiston Facility Load as Contracted For / Committed To (CF/CT)" and "Avista Corporation's Comments on the Bonneville Power Administration's (BPA) New Large Single Load (NLSL) Determination for the Potlatch Lewiston Facility Load" both filings submitted July 3, 2008. Avista understands BPA was not able to evaluate the referenced Avista filings in time for consideration in the FY'09 Draft ASC Report, and we look forward to the ongoing work to resolve these issues.

    c. **BPA's Response to Avista's Comment:** BPA is in the process of evaluating Avista's request for consideration of the determination of the Potlatch Lewiston Facility Load as Contracted For / Committed To (CF/CT). After a preliminary review of the findings, early indications show that the load will most likely meet the CF/CT qualifications. For forecasting purposes to this revised report, assuming a CF/CT status, BPA will reduce the quantity of Avista's NLSL.

2. **Contract System Cost**: New Large Single Load (NLSL) Costs

    a. **Analysis of Position and Decision**: Section 5 (c) of the Northwest Power Act does not permit costs of servicing a NLSL to be included in the calculations of a Utility's ASC, and therefore, BPA removed the NLSL and associated costs from the Appendix 1 amended filing. The results are noted in Schedule 4 of the amended Appendix 1 filing and in Table 2 at the end of this report. In addition, BPA will publish the resource cost determinations to NLSL work papers at the ASCM website.

b. **Avista's Comment on Decision:** [Avista submitted to BPA] "Informal Request for Consideration of the Determination of the Potlatch Lewiston Facility Load as Contracted For / Committed To (CF/CT)" and "Avista Corporation's Comments on the Bonneville Power Administration's (BPA) New Large Single Load (NLSL) Determination for the Potlatch Lewiston Facility Load" submitted July 3, 2008. Avista understands BPA was not able to evaluate the referenced Avista filings in time for consideration in the FY'09 Draft ASC Report, and we look forward to the ongoing work to resolve these issues.

c. **BPA's Response to Avista's Comment:** BPA is in the process of evaluating Avista's request for consideration of the determination of the Potlatch Lewiston Facility Load as Contracted For / Committed To (CF/CT). After a preliminary review of the findings, early indications show that the load will most likely meet the CF/CT qualifications. For forecasting purposes to this revised report, assuming a CF/CT status, BPA will reduce the quantity of Avista's NLSL. As a result, the cost to serve the NLSL resources is also reduced. As appropriate, BPA will review the NLSL resource costs once the final CF/CT determination has been completed.

C. Identification and Analysis of Issues based on Comments to the August 4, 2008 Revised DRAFT ASC Report

SCHEDULE 1: Plant Investment/Rate Base–

1. For Account 108, line item "**Capital Leases - Common Plant"** and **In-Service: Depreciation of Common Plant**

a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

b. Analysis of Position and Decision: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments** (**Electric)**, Account 114, line 92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4 report

SCHEDULE 3: Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/Rate Base*** **(Acquisition Adjustments (Electric)**, (cell E92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses:

   b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4 report

SCHEDULE 3B: Other Included – no changes from the August 4 report

SCHEDULE 4: Average System Cost – no changes from the August 4 report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

    a. Statement of Issue: For Labor Ratio Input: line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

    b. Analysis of Position and Decision: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908: all exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

D. Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC are allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that Utility's retail load during the BPA rate period. The change in ASC must meet the materiality threshold as the change in ASC resulting from adding major new resources, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more.

Table 1 below identifies the New Resource Additions information provided from Avista for FY 2008 only (year ending December 2007). None of Avista's individual resource additions for FY 2008 met the materiality threshold of 2.5 percent as described above, either as a single resource or when combined together. Therefore, the costs associated with the New Resource Additions were not included the in calculation of the ASC. Tables 1, ASC New Resource Additions identifies the values.

Table 1: ASC New Resource Additions

	FY 2006	FY 2007	FY 2008	FY 2009
Production Rate Base			17,149,000	
Plant Material and Supplies Rate Base				
Fuel Stock Rate Base				
Production O&M Expense				
Production Depreciation Expense			495,806	
Power Purchases Expense				
Production Property Tax			257,235	
Transmission Rate Base			35,149,533	
Transmission Depreciation Rate Base			1,324,018	
Transmission O&M Expense				
Transmission Contracts Expense				
Transmission Property Tax Expense			822,434	
(Expected) Annual Generation (MWh)			39,070	

E. Response to Exchange Period ASC New Resource Additions

Avista's Comment to Exchange Period ASC New Resource Additions Table 1: ASC New Resource Additions

1. Amount used as Transmission Rate Base is incorrect and does not agree with the filing made on May 7. This dollar figure should be $55,162,008.

2. Amount used as Transmission Property Tax Expense is incorrect and does not agree with the filing made on May 7. This amount should be $827,429.

3. Avista does not know how these changes impact the materiality threshold, but assumes it may not meet the 2.5 percent limit.

BPA's Response to Avista's Comment

1. BPA agrees with Avista in that the amount used as Transmission Rate Base was incorrect. After reviewing the data submitted by Avista, it was determined an error was made in transferring the information. The dollar figure was corrected to $55,162,008.

2. BPA agrees with Avista in that the amount used as Transmission Property Tax Expense is incorrect. This amount was corrected to $827,429. After reviewing the data submitted by Avista, it was determined an error was made in transferring the information.

3. The correction to the Transmission Rate Base and Transmission Property Tax Expense did not change the impact on the 2.5% materiality threshold.

Table 1 corrections:

Transmission Rate Base			55,162,008	
Transmission Property Tax Expense			827,429	

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining Avista's forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and Avista's ASCs published in the July 8, 2008 report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and Avista's ASCs as appropriate and as a result of Avista's comments to the July 8, 2008 report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and Avista's ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	417,140,810	415,528,934	416,917,558	425,979,883	434,818,090
Transmission	59,173,592	58,608,141	58,095,284	57,556,386	57,046,824
NLSL Fully Allocated Cost ($/MWh)	75.14	71.58	69.07	67.89	66.80
(Less) NLSL Costs	41,426,265	39,464,450	38,082,888	37,432,406	36,827,560
Total Contract System Cost	**434,888,137**	**434,672,625**	**436,929,954**	**446,103,863**	**455,037,354**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	9,163,546	9,349,910	9,508,840	9,709,299	9,890,789
(Less) NLSL	551,335	551,335	551,335	551,335	551,335
Total Retail Load (Net or NLSL)	8,612,211	8,798,575	8,957,505	9,157,964	9,339,454
Distribution Loss	480,170	489,935	498,263	508,767	518,277
Total Contract System Load	**9,092,380**	**9,288,510**	**9,455,768**	**9,666,731**	**9,857,731**

AVERAGE SYSTEM COST

ASC ($/MWh)	**47.83**	**46.80**	**46.21**	**46.15**	**46.16**

Revised Table 2: FY 2009-2013 ASC Summary – August 4, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	413,376,834	405,411,210	416,874,078	425,600,061	434,850,448
Transmission	59,361,336	58,795,749	58,282,778	57,743,730	57,234,036
NLSL Fully Allocated Cost ($/MWh)	77.58	71.83	72.31	70.95	69.93
(Less) NLSL Costs	4,766,933	4,413,591	4,443,632	4,359,877	4,297,035
Total Contract System Cost	**467,971,236**	**459,793,368**	**470,713,225**	**478,983,914**	**487,787,449**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	9,163,546	9,349,910	9,508,840	9,709,299	9,890,789
(Less) NLSL	61,449	61,449	61,449	61,449	61,449
Total Retail Load (Net or NLSL)	9,102,097	9,288,461	9,447,391	9,647,850	9,829,340
Distribution Loss	480,170	489,935	498,263	508,767	518,277
Total Contract System Load	**9,582,267**	**9,778,396**	**9,945,654**	**10,156,617**	**10,347,617**

AVERAGE SYSTEM COST

ASC ($/MWh)	**48.84**	**47.02**	**47.33**	**47.16**	**47.14**

Final Table 2: FY 2009-2013 ASC Summary – September 11, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	426,553,083	418,576,017	429,968,037	438,593,985	447,787,283
Transmission	60,000,388	59,329,051	58,710,865	58,065,786	57,450,436
NLSL Fully Allocated Cost ($/MWh)	77.64	71.88	72.36	70.98	69.95
(Less) NLSL Costs	4,771,005	4,416,922	4,446,260	4,361,813	4,298,313
Total Contract System Cost	**481,782,465**	**473,488,147**	**484,232,641**	**492,297,957**	**500,939,406**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	9,163,546	9,349,910	9,508,840	9,709,299	9,890,789
(Less) NLSL	61,449	61,449	61,449	61,449	61,449
Total Retail Load (Net or NLSL)	9,102,097	9,288,461	9,447,391	9,647,850	9,829,340
Distribution Loss	480,170	489,935	498,263	508,767	518,277
Total Contract System Load	**9,582,267**	**9,778,396**	**9,945,654**	**10,156,617**	**10,347,617**

AVERAGE SYSTEM COST

ASC ($/MWh)	**50.28**	**48.42**	**48.69**	**48.47**	**48.41**

VI. BPA STATEMENT

This ASC determination is BPAs best estimate of Avista's FY 2009 ASC based on the information and data provided from Avista during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination for FY 2009. This determination is made solely for the purpose of providing estimated FY 2009 ASCs for use in the development of BPAs FY 2009 power rates in BPAs WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009.

Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such reviews will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance with the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System of Avista for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The Final Appendix 1 Filing, Forecast Model and NLSL assessment used to calculate Avista's ASCs can be viewed at BPAs ASC website:
http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

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FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

CENTRALIA CITY LIGHT

Docket Number: CE-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

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TABLE OF CONTENTS

Section **Page**

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I. FILING DATA

Utility	Parties to the Filing
Centralia City Light 1100 North Tower Avenue Centralia, WA 98531	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept.11, 2008 Final
Production Cost	$7,945,359	$7,945,359	$7,945,359	$7,945,359
Transmission Cost	$1,323,997	$1,323,997	$1,323,997	$1,323,997
(Less) New Large Single Load Costs	$0	$0	$0	
Total Contract System Cost	$9,269,357	$9,269,357	$9,269,357	$9,269,357
Total Retail Load (MWh)	234,779	234,779	234,779	234,779
(Less) New Large Single Load	0	0	0	
Total Retail Load (Net NLSL)	234,779	234,779	234,779	234,779
Plus Distribution Losses	11,739	11,739	11,739	11,739
Total Contract System Load (MWh)	246,518	246,518	246,518	246,518
FY 2006 Base Period ASC ($/MWh)	**37.60**	**37.60**	**37.60**	**37.60**

B. FY 2009 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept.11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**30.83**	**34.93**	**35.56**

C. FY 2009 (Exchange Period) ASC with New Resource Additions ($/MWh)

Centralia has no new resource additions.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. See 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging utilities agreed to a number of termination agreements that provided for payments to each utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. <u>ASC Determination Process Guidelines and Expedited Review Process</u>

The purpose of BPA's expedited review process is to estimate exchanging Utilities' ASCs for FY 2009 and to incorporate the ASCs into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding rely on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities, which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance with the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1. The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a base period ASC determination, BPA used the ASC Forecast model, an Excel-based spreadsheet, to escalate the base year ASC forward to the effective rate period, FY 2009 (October 1, 2008, through September 30, 2009). The base year and forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capitol (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and administrative and general expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1, in order to determine the Utility's return on investment.

Investor Owned Utilities (IOUs) use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For Consumer Owned Utilities (COUs), the rate of return is equal to the COU's weighted cost of debt.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as described above. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items. The schedule also lists the load information, as defined below, and calculates the Utility's ASC.

Contract System Cost:
The Contract System Cost is the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Load:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any New Large Single Load(s) (NLSL).

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Sales for Resale

Purchased Power is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1 pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A new large single load (NLSL) is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10 aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of <u>all</u> post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro-rata basis using salary and wage data for production, transmission, and distribution/other functions included in the Utility's most recently filed Form 1. For COUs, comparable data is used based on a cost of service study used as the basis for retail rates at the time of review.

D. ASC Forecast

Once BPA determines the Base Period ASC, it applies this data in an Excel-based forecasting model to escalate the base year ASC data forward to the Exchange Period. For purposes of this expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its Priority Firm (PF) Power Rate and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Costs

Forecast Contract System Costs (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with an Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5 percent change to ASC. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of the major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. Identification and Analysis of Issues from the May 7, 2008, ASC Appendix 1 Filing

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Cost and Contract System Load filed on May 7, 2008 by Centralia , and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base – No changes made.

SCHEDULE 1A: Cash Working Capital – No changes made.

SCHEDULE 2: Capital Structure and Rate of Return – No changes made.

SCHEDULE 3: Expenses- No changes made.

SCHEDULE 3A: Taxes – No changes made.

SCHEDULE 3B: Other Included Items – No changes made.

SCHEDULE 4: Average System Cost

1. **Distribution Loss**:

   a. Statement of Issue: In its filing, Centralia used a 5 percent Distribution Loss Factor to determine its ASC.

   b. Statement of Facts: The May 7, 2008, Appendix 1 template did not require a Utility to complete a Distribution Loss Study. The ASCM ROD allows a participating Utility that has the ability to directly measure distribution losses on its system to submit such measurements, subject to BPA review and approval, with its ASC filing. Utilities that do not have the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years.

      Utilities that do not have the ability to directly measure distribution losses on their system and do not submit a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

   c. Analysis of Position and Decision: BPA was unable to obtain from a public source the requisite five years of distribution losses necessary to determine distribution losses consistent with the ASCM ROD, Section 4.10.5. BPA will request such data from Centralia, but for purposes of this expedited filing will use a 5 percent Distribution Loss Factor to determine its ASC.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – No changes made.

SUPPORTING DOCUMENTATION: Salaries and Wages – No changes made.

SUPPORTING DOCUMENTATION: Ratios – Though certain functionalization changes were made to the Appendix 1 template subsequent to the May 7, 2008, Centralia had no data to populate the affected accounts.

B. Identification and Analysis of Issues Based on Comments to the July 8, 2008, ASC Draft Report

No comments were submitted.

C. <u>Identification and Analysis of Issues Based on comments to the August 4, 2008 Revised Draft ASC Report</u>

SCHEDULE 1: Plant Investment/Rate Base–

1. For Account 108, line item "**Capital Leases - Common Plant"** and **In-Service: Depreciation of Common Plant**

   a. <u>Statement of Issue: </u>Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

   b. <u>Analysis of Position and Decision</u>: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments"**

   a. <u>Statement of Issue</u>: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments"** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments** (**Electric))**, Account 114, line 92 in electronic template).

   b. <u>Analysis of Position and Decision</u>: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4, 2008, report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4, 2008, report

SCHEDULE 3: Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)"**

    a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)"** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/Rate Base* (Acquisition Adjustments (Electric))**, (cell E92 in electronic template).

    b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

    a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses.

    b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4, 2008, report

SCHEDULE 3B: Other Included – no changes from the August 4, 2008, report

SCHEDULE 4: Average System Cost – no changes from the August 4, 2008, report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

    a. Statement of Issue: For Labor Ratio Input line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

    b. Analysis of Position and Decision: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908. All exchangeable conservation costs may be functionalized to

Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

D. Exchange Period ASC New Resource Additions

Centralia has no projected new resource additions.

Table 1: ASC New Resource Additions (Not Applicable)

	FY 2006	FY 2007	FY 2008	FY 2009
Production Rate Base				
Plant Material and Supplies Rate Base				
Fuel Stock Rate Base				
Production O&M Expense				
Production Depreciation Expense				
Power Purchases Expense				
Production Property Tax				

Transmission Rate Base				
Transmission Depreciation Rate Base				
Transmission O&M Expense				
Transmission Contracts Expense				
Transmission Property Tax Expense				

(Expected) Annual Generation (MWh)				

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining Centralia's forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and Centralia's ASCs published in the July 8, 2008, report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and Centralia's ASCs from the July 8, 2008, report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and Centralia's ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	7,558,253	7,425,246	7,667,965	7,922,875	7,934,267
Transmission	1,409,706,	1,433,391	1,460,765	1,489,055	1,518,732
NLSL Fully Allocated Cost ($/MWh)	0	0	0	0	0
(Less) NLSL Costs	0	0	0	0	0
Total Contract System Cost	**8,967,960**	**8,858,637**	**9,128,731**	**9,411,930**	**9,452,998**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	276,991	283,912	290,833	298,227	305,531
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net or NLSL)	276,991	283,912	290,833	298,227	305,531
Distribution Loss	13,850	14,196	14,542	14,911	15,211
Total Contract System Load	**290,840**	**298,108**	**305,375**	**313,138**	**320,808**

AVERAGE SYSTEM COST

ASC ($/MWh)	**30.83**	**29.72**	**29.89**	**30.06**	**29.47**

Revised Table 2: FY 2009-2013 ASC Summary – August 4, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	8,749,392	9,210,058	9,444,457	10,052,746	10,307,526
Transmission	1,409,706,	1,433,391	1,460,765	1,489,055	1,518,732
NLSL Fully Allocated Cost ($/MWh)	0	0	0	0	0
(Less) NLSL Costs	0	0	0	0	0
Total Contract System Cost	**10,159,098**	**10,643,449**	**10,905,222**	**11,541,801**	**11,826,258**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	276,991	283,912	290,833	298,227	305,531
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net or NLSL)	276,991	283,912	290,833	298,227	305,531
Distribution Loss	13,850	14,196	14,542	14,911	15,211
Total Contract System Load	**290,840**	**298,108**	**305,375**	**313,138**	**320,808**

AVERAGE SYSTEM COST

ASC ($/MWh)	**34.93**	**35.70**	**35.71**	**36.86**	**36.86**

Final Table 2: FY 2009-2013 ASC Summary – September 11, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	8,931,977	9,508,022	9,740,887	10,495,488	10,753,858
Transmission	1,410,451	1,434,131	1,461,501	1,489,785	1,519,456
NLSL Fully Allocated Cost ($/MWh)	4.85	4.81	4.79	4.76	4.74
(Less) NLSL Costs	0	0	0	0	0
Total Contract System Cost	**10,342,428**	**10,942,154**	**11,202,389**	**11,985,273**	**12,273,314**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	276,991	283,912	290,833	298,227	305,531
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net or NLSL)	276,991	283,912	290,833	298,227	305,531
Distribution Loss	13,850	14,196	14,542	14,911	15,277
Total Contract System Load	**290,840**	**298,108**	**305,375**	**313,138**	**320,808**

AVERAGE SYSTEM COST

ASC ($/MWh)	**35.56**	**36.71**	**36.68**	**38.27**	**38.26**

VI. BPA STATEMENT

This Final ASC determination does not change the as-filed Base Period 2006 ASC of $37.60 per MWh. ASCs for years 2009 through 2013 shown in Final Table 2 above are increased to reflect increases to the price of power forecast to satisfy Centralia's load growth.

This ASC determination is BPA's best estimate of Centralia's FY 2009 ASC based on the information and data provided by Centralia during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination for FY 2009. This determination is made solely for the purpose of providing estimated FY 2009 ASCs for use in the development of BPA's FY 2009 power rates in BPA's WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such review will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance with the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System of Centralia for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The Final Appendix 1 Filing and Forecast Model used to calculate Centralia's (unchanged) Base ASC and forecast ASCs can be viewed at BPA ASC website: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

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FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

Public Utility District No. 1 of Franklin County, Washington

Docket Number: FR-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

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TABLE OF CONTENTS

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I. FILING DATA

Utility	Parties to the Filing
Public Utility District No. 1 of Franklin County PO Box 2407 Pasco, Washington 99302-2407	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
Production Cost	$44,431,086	$43,784,794	$43,784,794	$43,784,794
Transmission Cost	353,594	353,594	353,594	353,594
(Less) New Large Single Load Costs	0	0	0	0
Contract System Cost	$44,784,680	$44,138,388	$44,138,388	$44,138,388
Total Retail Load (MWh)	835,781	835,781	835,781	835,781
(Less) New Large Single Load	0	0	0	0
Total Retail Load (Net NLSL)	835,781	835,781	835,781	835,781
Plus Distribution Losses	41,789	41,789	41,789	41,789
Contract System Load (MWh)	877,570	877,570	877,570	877,570
FY 2006 Base Period ASC ($/MWh)	**$51.03**	**$50.30**	**$50.30**	**$50.30**

B. FY 09 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**$48.64**	**$43.97**	**$45.74**

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging Utilities agreed to a number of termination agreements that provided for payments to each Utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest

Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing Utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. ASC Determination Process Guidelines and Expedited Review Process

The purpose of BPA's expedited review process was to estimate exchanging Utilities' ASCs for FY 2009 that could be incorporated into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding relied on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance to the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1.

The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.
In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a Base Period ASC determination,

BPA used the ASC Forecast model, an Excel-based spreadsheet, to escalate the Base Period ASC forward to the effective rate period, FY 2009 (October 1, 2008 thru September 30, 2009). The Base Period and Forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1 to determine the Utility's return on investment.

IOUs use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For Consumer-Owned Utilities (COU), the rate of return is equal to the COU's weighted cost of debt times total rate base.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as outlined in the ASCM, Table 1. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items. The schedule also lists the load information, as defined below, and calculates the Utility's ASC.

<u>Contract System Cost</u>:
The Contract System Cost is the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

<u>Contract System Load</u>:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any New Large Single Load(s) (NLSL).

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Sales for Resale

The Purchased Power (excluding REP reversal expenses) is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1, pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A NLSL is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of <u>all</u> post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro rata basis using salary and wage data for Production, Transmission, and Distribution/other functions included in the Utility's most recently filed Form 1. For COUs, comparable data is used based on the cost of service analysis (COSA) study used as the basis for retail rates in effect during the Base Year filing.

D. <u>ASC Forecast</u>

Once BPA determines the Base Period ASC, it applies this data in an Excel-based forecasting model to escalate the base year ASC data forward to the Exchange Period. For purposes of the expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Cost

Forecast Contract System Cost (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5%. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of the major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. Identification and Analysis of Issues from the May 7, 2008 ASC Appendix 1 Filing

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Cost and Contract System Load filed on May 7, 2008 by Public Utility District No. 1 of Franklin County, Washington (Franklin), and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base- no changes

SCHEDULE 1A: Cash Working Capital – no changes

SCHEDULE 2: Capital Structure and Rate of Return – no changes

SCHEDULE 3: Expenses

1. **Purchased Power**:

   a. Statement of Issue: In its filing, Franklin included different values for Purchased Power Expense on Schedule 3 and on the Purchased Power & Sales for Resale (PP & OSS) Worksheet..

b. Statement of Facts: The May 7th filing Appendix 1 included a value of $48,806,613 in Account 555, Purchased Power Expense on Schedule 3. On the PP & OSS Worksheet, Franklin included a value of $55,433,767 for Purchased Power Expense. Communication with Franklin concerning the discrepancy resulted in Franklin sending a revised value for Purchased Power Expense of $48,160,321.

c. Analysis of Position and Decision: BPA accepted Franklin's revised value for Purchased Power Expense and revised the ASC Template accordingly.

SCHEDULE 3A: Taxes – no changes

SCHEDULE 3B: Other Included Items – no changes

SCHEDULE 4: Average System Cost

2. **Distribution Losses**:

a. Statement of Issue: In its filing, Franklin used a 5% Distribution Loss Factor in determination of its ASC.

b. Statement of Facts: The May 7th filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years.

Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

c. Analysis of Position and Decision: For purposes of the expedited filing, BPA will use the 5% Distribution Loss Factor calculation pending additional information from Franklin concerning either its Actual distribution losses from either direct measurement, a distribution loss study, of submittal of its total losses. BPA will make the adjustment for Distribution Losses in the Final Report if it receives the data from Franklin as outlined in the ASCM ROD, Section 4.10.5.

3. **Contract System Load:** ***no Changes***

4. **Contract System Cost:** Changes from Schedule 3

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale –
Revised as discussed in Issue 1 on Schedule 3 - Expenses, Purchased Power Expense.

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes

SUPPORTING DOCUMENTATION: Labor Ratios

5. **Maintenance of General Plant (GPM) Ratio:** Miscellaneous Equipment

   a. Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

   b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

   c. Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

B. Identification and Analysis of Issues from comments to the August 4, 2008 ASC Draft Report

SCHEDULE 1: Plant Investment/Rate Base–

1. For Account 108, line item "**Capital Leases - Common Plant"** and **In-Service: Depreciation of Common Plant**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

   b. Analysis of Position and Decision: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments** (**Electric)**, Account 114, line 92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4, 2008 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4, 2008 report

SCHEDULE 3: Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/Rate Base* (Acquisition Adjustments (Electric)**, (cell E92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses:

b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4 2008 report

SCHEDULE 3B: Other Included – no changes from the August 4 2008 report

SCHEDULE 4: Average System Cost – no changes from the August 4 2008 report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

   a. Statement of Issue: For Labor Ratio Input: line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

   b. Analysis of Position and Decision: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908: all exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

C. Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC are allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that Utility's retail load during the BPA rate period. The change in ASC must meet the materiality threshold as the change in ASC resulting from adding major new resources, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more.

Franklin did not submit information on new resources with their ASC filing.

Table 1: ASC New Resource Additions

	FY 2006	FY 2007	FY 2008	FY 2009
Production Rate Base				
Plant Material and Supplies Rate Base				
Fuel Stock Rate Base				
Production O&M Expense				
Production Depreciation Expense				
Power Purchases Expense				
Production Property Tax				
Transmission Rate Base				
Transmission Depreciation Rate Base				
Transmission O&M Expense				
Transmission Contracts Expense				
Transmission Property Tax Expense				
(Expected) Annual Generation (MWh)				

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining Franklin County PUD's forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and Franklin County PUD's ASCs published in the July 8, 2008 report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and Franklin County PUD's ASCs as appropriate and as a result of Franklin County PUD's comments to the July 8, 2008 report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and Franklin County PUD's ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: Draft FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	$49,440,108	$49,940,972	$52,301,506	$54,770,075	$56,112,121
Transmission	334,172	329,203	324,403	319,484	314,480
NLSL Fully Allocated Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00
(Less) NLSL Costs	0	0	0	0	0
Contract System Cost	**$49,774,280**	**$50,270,175**	**$52,625,909**	**$55,089,559**	**$56,426,601**

CONTRCT SYSTEM LOAD

Total Retail Load @ Meter	974,500	996,750	1,014,000	1,030,000	1,048,250
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net of NLSL)	974,500	996,750	1,014,000	1,030,000	1,048,250
Distribution Losses	48,725	49,838	50,700	51,500	52,413
Contract System Load	**1,023,225**	**1,046,588**	**1,064,700**	**1,081,500**	**1,100,663**

AVERAGE SYSTEM COST

ASC ($/MWh)	**$48.64**	**$48.03**	**$49.43**	**$50.94**	**$51.27**

Table 2: Revised FY 2009-2013 ASC Summary - August 4, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	$44,654,069	$46,861,614	$47,365,237	$50,200,684	$50,731,010
Transmission	334,172	329,203	324,403	319,484	314,480
NLSL Resource Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00
(Less) NLSL Costs	0	0	0	0	0
Contract System Cost	**$44,988,240**	**$47,190,817**	**$47,689,640**	**$50,520,167**	**$51,045,490**

CONTRCT SYSTEM LOAD

Total Retail Load @ Meter	974,500	996,750	1,014,000	1,030,000	1,048,250
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net of NLSL)	974,500	996,750	1,014,000	1,030,000	1,048,250
Distribution Losses	48,725	49,838	50,700	51,500	52,413
Contract System Load	**1,023,225**	**1,046,588**	**1,064,700**	**1,081,500**	**1,100,663**

AVERAGE SYSTEM COST

ASC ($/MWh)	**$43.97**	**$45.09**	**$44.79**	**$46.71**	**$46.38**

Table 2: Final FY 2009-2013 ASC Summary - September 11, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	$46,464,644	$49,467,433	$49,965,516	$53,756,643	$54,298,688
Transmission	339,921	334,953	330,161	325,252	320,254
NLSL Resource Cost ($/MWh)	0.33	0.32	0.31	0.30	0.29
(Less) NLSL Costs	0	0	0	0	0
Contract System Cost	**$46,804,565**	**$49,802,386**	**$50,295,677**	**$54,081,895**	**$54,618,941**

CONTRCT SYSTEM LOAD

Total Retail Load @ Meter	974,500	996,750	1,014,000	1,030,000	1,048,250
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net of NLSL)	974,500	996,750	1,014,000	1,030,000	1,048,250
Distribution Losses	48,725	49,838	50,700	51,500	52,413
Contract System Load	**1,023,225**	**1,046,588**	**1,064,700**	**1,081,500**	**1,100,663**

AVERAGE SYSTEM COST

ASC ($/MWh)	**$45.74**	**$47.59**	**$47.24**	**$50.01**	**$49.62**

VI. BPA STATEMENT

This ASC determination is BPA's best estimate of Franklin County PUD's FY 2009 ASC based on the information and data provided from Franklin County PUD during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination, FY 2009. This determination is made solely for purposes of providing estimated FY 2009 ASCs for use in the development of BPA's FY 2009 power rates in BPA's WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such review will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance to the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System Cost of Franklin County PUD for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The Final Appendix 1 Filing, Forecast Model, and resource cost determination to the NLSL assessment used to calculate Franklin County PUD's ASCs can be viewed at BPA ASC website:

http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

IDAHO POWER COMPANY

Docket Number: ID-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

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TABLE OF CONTENTS

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I. FILING DATA

Utility	Parties to the Filing
Idaho Power Company P.O. Box 70 (83707) Boise, ID 83702	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
Production Cost	$398,773,303	$398,771,211	$398,771,211	$399,101,933
Transmission Cost	$94,625,570	$94,642,415	$94,642,415	$94,642,415
(Less) New Large Single Load Costs	$0	$18,084,845	$26,461,649	$26,461,649
Total Contract System Cost	$493,398,873	$475,328,781	$466,951,978	$467,282,700
Total Retail Load (MWh)	13,939,314	13,939,314	13,939,314	13,939,314
(Less) New Large Single Load	0	385,440	385,440	385,440
Total Retail Load (Net NLSL)	13,939,314	13,553,874	13,553,874	13,553,874
Plus Distribution Losses	696,966	1,084,713	1,084,713	1,084,713
Total Contract System Load (MWh)	14,636,280	14,638,587	14,638,587	14,638,587
FY 2006 Base Period ASC ($/MWh)	**33.71**	**32.47**	**31.90**	**31.92**

B. FY 2009 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**33.68**	**33.53**	**33.86**

C. FY 2009 (Exchange Period) ASC with New Resource Additions ($/MWh)

Idaho Power provided BPA new resource information on May 9, 2008. BPA has confirmed with Idaho Power that the new resource is now on line. Cost and load information for this resource is shown in Table1 in Section III.B and such information is included in Table 2, Section V., final Expedited ASC Forecast for FY 2009-2013.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. See 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging utilities agreed to a number of termination agreements that provided for payments to each utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. ASC Determination Process Guidelines and Expedited Review Process

The purpose of BPA's expedited review process is to estimate exchanging Utilities' ASCs for FY 2009 for inclusion in BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding rely on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities, which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance with the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1. The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a base period ASC determination, BPA used the ASC Forecast model, an Excel-based spreadsheet, to escalate the base year ASC forward to the effective rate period, FY 2009 (October 1, 2008, through September 30, 2009). The base year and forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capitol (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and administrative and general expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1, in order to determine the Utility's return on investment.

Investor Owned Utilities (IOUs) use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For Consumer Owned Utilities (COUs), the rate of return is equal to the COU's weighted cost of debt.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as described above. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items.

Contract System Cost

The Contract System Cost is the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve a new large single load (NLSL) are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Load

The Contract System Load is the total regional retail load included in the Form 1, or for a COU (preference customer) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any NLSL.

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Sales for Resale

Purchased Power is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1 pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A new large single load (NLSL) is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10 aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro-rata basis using salary and wage data for production, transmission, and distribution/other functions included in the Utility's most recently filed FERC Form 1. For COUs, comparable data is used based on a cost of service study used as the basis for retail rates at the time of review.

D. ASC Forecast

The 2006 Base Period ASC is applied to an Excel-based forecasting model to escalate the base year ASC data forward to the Exchange Period. For purposes of this expedited process, the Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its Priority Firm (PF) Power Rate and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Cost

Forecast Contract System Cost (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with an Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5 percent change to ASC. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of any major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. Identification and Analysis of Issues from the May 7, 2008, ASC Appendix 1 Filing

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Cost and Contract System Load filed on May 7, 2008 by Idaho Power, and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base – No changes made except to the functionalization of cash working capital due to functionalization changes made subsequent to the May 7, 2008, filing.

SCHEDULE 1A: Cash Working Capital – No changes made except to the functionalization of cash working capital due to functionalization changes made subsequent to the May 7, 2008, filing.

SCHEDULE 2: Capital Structure and Rate of Return – No changes made except for carryover of Schedule 1 change discussed above.

SCHEDULE 3: Expenses- No changes except for a change to the functionalization of account number 935, Maintenance of General Plant, made subsequent to the May 7, 2008, filing.

SCHEDULE 3A: Taxes – Small change resulting from imposing a rounding convention to the interest rate calculations made subsequent to the May 7, 2008, filing.

SCHEDULE 3B: Other Included Items – Account 411.6, Gain from Disposition of Utility Plant, is functionalized to Production consistent with a functionalization change made subsequent to the May 7, 2008, filing.

SCHEDULE 4: Average System Cost

1. **Distribution Loss:**

Statement of Issue: In its filing, Idaho Power Company used a 5 percent Distribution Loss Factor to determine its ASC.

a. Statement of Facts: The May 7, 2008, Appendix 1 template did not require a Utility to complete a Distribution Loss Study to determine its Contract System Load. As outlined in the ASCM ROD, BPA allows a participating Utility that has the ability to directly measure distribution losses on its system to submit such measurements, subject to BPA review and approval, with its ASC filing. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years.

   Utilities that do not have the ability to directly measure distribution losses on their system, and that do not submit with the Appendix 1 a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing, will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

b. Analysis of Position and Decision: For purposes of this expedited filing, BPA completed the Distribution Loss Factor outlined in the ASCM ROD, Section 4.10.5. Idaho Power's Distribution Loss Factor is determined to be 7.78 percent.

2. **Contract System Load: New Large Single Load (NLSL)**

a. Statement of Issue: The Appendix 1 filing instructions for the May 7, 2008, submittal did not require information on possible NLSLs. BPA subsequently required that such data be included in the determination of a Utility's ASC.

b. Statement of Facts: Idaho Power submitted annual data identifying one potential NLSL ("Customer 1") whose power needs increased from 34 aMW in 1995 to 46 aMW in 1996. Idaho Power subsequently provided monthly data that confirmed an increase of greater than 10 aMW over 12 consecutive months during such years.

c. Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit the costs to serve an NLSL to be included in the calculation of a Utility's ASC. Customer 1 load in 2006 of 78 aMW is determined to be 44 aMW of NLSL, with the "grandfathered" 1995 load of 34 aMW excluded from NLSL status. BPA determined Idaho Power's 2006 NLSL Cost to be $68.65 per megawatt-hour. BPA determined the cost of serving the potential NLSL based on the fully allocated cost of all post-September 1, 1979, resources, major resource additions and long-term power purchases (5 years or longer contracts) used to determine Exchange Period ASCs as outlined in the ASCM ROD, section 4.5. Schedule 4 shows a Contract System Cost reduction of $26,461,649, reflecting the product of 44 aMW and $68.65/MWh, and a Contract System Load reduction of 385,440 MWh.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – No changes made.

SUPPORTING DOCUMENTATION: Salaries and Wages – No changes made.

SUPPORTING DOCUMENTATION: Ratios

1. **Maintenance of General Plant (GPM) Ratio:** Miscellaneous Equipment

a. Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

c. Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

B. Identification and Analysis of Issues Based on Comments on the July 8, 2008, Draft ASC Report

No comments were submitted.

C. Identification and Analysis of Issues Based on comments on the August 4, 2008, Revised Draft ASC Report

SCHEDULE 1: Plant Investment/Rate Base–

1. For **Account** 108, line item "**Capital Leases - Common Plant"** and **In-Service: Depreciation of Common Plant**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

   b. Analysis of Position and Decision: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments"**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments"** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments (Electric))**, Account 114, line 92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4, 2008, report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4, 2008, report

SCHEDULE 3: Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)"**

    a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)"** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/Rate Base* (Acquisition Adjustments (Electric))**, (cell E92 in electronic template).

    b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

    a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses.

    b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4, 2008, report

SCHEDULE 3B: Other Included – no changes from the August 4, 2008, report

SCHEDULE 4: Average System Cost - – no changes from the August 4, 2008, report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

   a. Statement of Issue: For Labor Ratio Input line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

   b. Analysis of Position and Decision: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908. All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

D. Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC may be made for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a Utility's retail load during the BPA rate period. The change to an established ASC must be "material," i.e., result in a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more. BPA determined a change in Idaho Power's ASC using the methods as described in the ASCM ROD, section 4.2.10.

Table 1 below identifies the New Resource Addition information provided by Idaho Power for FY 2008 only (year ending December 2007).

Table 1: ASC New Resource Addition

	FY 2006	FY 2007	FY 2008	FY 2009
Production Rate Base			64,771,248	
Plant Material and Supplies Rate Base				
Fuel Stock Rate Base			7,916,038	
Production O&M Expense				
Production Depreciation Expense			1,813,550	
Power Purchases Expense				
Property Insurance			130,229	

Transmission Rate Base				
Transmission Depreciation Rate Base				
Transmission O&M Expense				
Transmission Contracts Expense				
Transmission Property Tax Expense				

(Expected) Annual Generation (MWh)			59,568	

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining Idaho Power's forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and Idaho Power's ASCs published in the July 8, 2008, report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and Idaho Power's ASCs as a result of Idaho Power's comments to the July 8, 2008, report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and Idaho Power's ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	467,386136	478,991,400	492,183,198	500,999,123	513,889,955
Transmission	92,347,749	91,705,109	91,091,667	90,418,765	89,787,296
NLSL Fully Allocated Cost ($/MWh)	74.12	72.28	71.09	70.74	70.36
(Less) NLSL Costs	28,566,965	27,859,851	27,400,275	27,264,525	27,119,667
Total Contract System Cost	**531,166,920**	**542,836,657**	**555,874,590**	**564,153,366**	**576,557,584**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	14,990,809	15,256,830	15,481,163	15,593,539	15,755,103
(Less) NLSL	385,440	385,440	385,440	385,440	385,440
Total Retail Load (Net or NLSL)	14,605,369	14,871,390	15,095,723	15,208,099	15,369,663
Distribution Loss	1,166,538	1,187,238	1,204,695	1,213,440	1,226,012
Total Contract System Load	**15,771,907**	**16,058,628**	**16,300,418**	**16,421,539**	**16595675**

AVERAGE SYSTEM COST

ASC ($/MWh)	**33.68**	**33.80**	**34.10**	**34.35**	**34.74**

Revised Table 2: FY 2009-2013 ASC Summary – August 4, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	466,891,079	477,582,472	492,592,137	501,415,361	514,475,248
Transmission	92,347,749	91,705,109	91,091,667	90,418,765	89,787,296
NLSL Fully Allocated Cost ($/MWh)	79.04	75.94	75.80	75.39	75.01
(Less) NLSL Costs	30,463,453	29,269,076	29,216,049	29,058,258	28,910,883
Total Contract System Cost	**531,166,920**	**542,836,657**	**555,874,590**	**564,153,366**	**576,557,584**

CONTRCT SYSTEM LOAD

Total Retail Load @ Meter	14,990,809	15,256,830	15,481,163	15,593,539	15,755,103
(Less) NLSL	385,440	385,440	385,440	385,440	385,440
Total Retail Load (Net or NLSL)	14,605,369	14,871,390	15,095,723	15,208,099	15,369,663
Distribution Loss	1,166,538	1,187,238	1,204,695	1,213,440	1,226,012
Total Contract System Load	**15,771,907**	**16,058,628**	**16,300,418**	**16,421,539**	**16595675**

AVERAGE SYSTEM COST

ASC ($/MWh)	**33.53**	**33.63**	**34.02**	**34.27**	**34.67**

Final Table 2: FY 2009-2013 ASC Summary – September 11,2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	470,949,913	481,694,355	496,739,225	505,581,825	518,655,158
Transmission	93,579,418	92,933,257	92,316,991	91,643,186	91,009,961
NLSL Fully Allocated Cost ($/MWh)	79.11	76.01	75.87	75.46	75.08
(Less) NLSL Costs	30,492,835	29,297,863	29,244,354	29,086,338	28,938,635
Total Contract System Cost	**534,036,495**	**545,329,749**	**559,811,862**	**568,138,673**	**580,726,484**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	14,990,809	15,256,830	15,481,163	15,593,539	15,755,103
(Less) NLSL	385,440	385,440	385,440	385,440	385,440
Total Retail Load (Net or NLSL)	14,605,369	14,871,390	15,095,723	15,208,099	15,369,663
Distribution Loss	1,166,538	1,187,238	1,204,695	1,213,440	1,226,012
Total Contract System Load	**15,771,907**	**16,058,628**	**16,300,418**	**16,421,539**	**16,595,675**

AVERAGE SYSTEM COST

ASC ($/MWh)	**33.86**	**33.96**	**34.34**	**34.60**	**34.99**

VI. BPA STATEMENT

This Final ASC determination reflects an increase in the cost to serve Idaho Power's NLSL. ASCs for years 2009 through 2013 shown in Final Table 2 above are increased to reflect such change.

This ASC determination is BPA's best estimate of Idaho Power's FY 2009 ASC based on the information and data provided from Idaho Power during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination for FY 2009. This determination is made solely for the purpose of providing estimated FY 2009 ASCs for use in the development of BPA's FY 2009 power rates in BPA's WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such reviews will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance with the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System of Idaho Power for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The Final Appendix 1 Filing, Forecast Model and NLSL assessment used to calculate Idaho Power's ASCs can be viewed at BPA's ASC website:
http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

NorthWestern Corporation

Docket Number: NW-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

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TABLE OF CONTENTS

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I. FILING DATA

Utility	Parties to the Filing
NorthWestern Corporation 40 East Broadway Butte, MT. 57901	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept.11, 2008 Final
Production Cost	$279,471,036	$279,471,076	$279,471,076	$279,471,076
Transmission Cost	52,689,522	52,695,962	52,695,962	52,695,962
(Less) New Large Single Load Costs	0	0	0	0
Contract System Cost	$332,160,558	$332,167,038	$332,167,038	$332,167,038
Total Retail Load (MWh)	5,749,741	5,749,741	5,749,741	5,749,741
(Less) NLSL	0	0	0	0
Total Retail Load (Net of NLSL)	5,749,741	5,749,741	5,749,741	5,749,741
Plus Distribution Losses	287,487	287,487	287,487	287,487
Contract System Load (MWh)	6,037,228	6,037,228	6,037,228	6,037,228
FY 2006 Base Period ASC ($/MWh)	**$55.02**	**$53.46**	**$53.46**	**$53.46**

B. FY 09 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**$54.62**	**$54.74**	**$54.84**

C. FY 09 (Exchange Period) ASC with New Resource Additions ($/MWh)

FY 2007-2009 New Resource Additions: N/A

There are no New Resource Additions recorded.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging Utilities agreed to a number of termination agreements that provided for payments to each Utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing Utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. ASC Determination Process Guidelines and Expedited Review Process

The purpose of BPA's expedited review process is to estimate exchanging Utilities' ASCs for FY 2009 that could be incorporated into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding rely on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance to the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1.

The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a Base Period ASC determination, BPA used the ASC Forecast model, an Excel-based spreadsheet, to escalate the Base Period ASC forward to the effective rate period, FY 2009 (October 1, 2008 through September 30, 2009). The Base Period and Forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1 to determine the Utility's return on investment.

IOUs use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For Consumer-Owned Utilities (COU), the rate of return is equal to the COU's weighted cost of debt times total rate base.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as outlined in the ASCM, Table 1. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items. The schedule also lists the load information, as defined below, and calculates the Utility's ASC.

Contract System Cost:
The Contract System Cost is the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Load:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any New Large Single Load(s) (NLSL).

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Sales for Resale

The Purchased Power is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1, pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A NLSL is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro rata basis using salary and wage data for Production, Transmission, and Distribution/other functions included in the Utility's most recently filed Form 1. For COUs, comparable data is used based on the cost of service analysis (COSA) study used as the basis for retail rates in effect during the Base Year filing.

D. ASC Forecast

The Base Period ASC is applied to an Excel-based forecasting model to escalate the Base Period ASC data forward to the Exchange Period. For purposes of the expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Cost

Forecast Contract System Cost (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5%. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of any major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of the major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. Identification and Analysis of Issues from the May 7, 2008 ASC Appendix 1 Filing.

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Cost and Contract System Load filed on May 7, 2008 by NorthWestern Corporation (NorthWestern), and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base – no changes

SCHEDULE 1A: Cash Working Capital – no changes

SCHEDULE 2: Capital Structure and Rate of Return – no changes

SCHEDULE 3: Expenses – no changes

1. **Common Plant**:

   a. Statement of Issue: Inadequate documentation and support of NorthWestern's allocation of Common Plant included different values for

Purchased Power Expense on Schedule 3 and on the Purchased Power & Sales for Resale (PP & OSS) Worksheet.

b. Statement of Facts: In its filing May 7, 2008 Filing, NorthWestern did not properly document and support its allocation of Common Plant between its Electric and Gas divisions, for its electric division Common Plant, did provided support for its allocation between Production, Transmission and Distribution/Other. In response to BPA's Issue's List, Northwestern supplied additional documentation for the allocation of Common Plant.

c. Analysis of Position and Decision: BPA accepted NorthWestern's submittal of additional documentation for Common Plant Allocation.

SCHEDULE 3A: Taxes – no changes

SCHEDULE 3B: Other Included Items – no changes

SCHEDULE 4: Average System Cost

2. **Distribution Losses**:

a. Statement of Issue: In its filing, NorthWestern used a 5% Distribution Loss Factor in determination of its ASC.

b. Statement of Facts: The May 7th filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years.

Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

c. Analysis of Position and Decision: For purposes of the expedited filing, BPA completed the Distribution Loss Factor calculation outlined in the ASCM ROD, Section 4.10.5.

3. **Contract System Load:** ***no changes***

4. **Contract System Cost:** ***no changes***

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale –
Revised as discussed in Issue 1 on Schedule 3 - Expenses, Purchased Power Expense.

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes

SUPPORTING DOCUMENTATION: Labor Ratios

5. **Maintenance of General Plant (GPM) Ratio:** Miscellaneous Equipment

   a. Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

   b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

   c. Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

B. Identification and Analysis of Issues from comments to the July 8, 2008 ASC Draft Report

SCHEDULE 1: Plant Investment/Rate Base: – no changes

SCHEDULE 1A: Cash Working Capital – no changes

SCHEDULE 2: Capital Structure and Rate of Return: – no changes

SCHEDULE 3: Expenses: no changes

SCHEDULE 3A: Taxes: no changes

SCHEDULE 3B: Other Included Items: no changes

SCHEDULE 4: Average System Cost: no changes

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – no changes

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes

SUPPORTING DOCUMENTATION: Labor Ratios – no changes

C. Identification and Analysis of Issues from comments to the August 4, 2008 ASC Draft Report

SCHEDULE 1: Plant Investment/Rate Base–

1. For Account 108, line item "**Capital Leases - Common Plant"** and **In-Service: Depreciation of Common Plant**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

   b. Analysis of Position and Decision: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments** (**Electric)**, Account 114, line 92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4 2008 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4 2008 report

SCHEDULE 3: – Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/ Rate Base* (Acquisition Adjustments (Electric)**, (cell E92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses:

   b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4 2008 report

SCHEDULE 3B: Other Included – no changes from the August 4 2008 report

SCHEDULE 4: Average System Cost – no changes from the August 4 2008 report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

   a. Statement of Issue: For Labor Ratio Input: line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

b. <u>Analysis of Position and Decision</u>: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908: all exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

D. Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC are allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that Utility's retail load during the BPA rate period. The change in ASC must meet the materiality threshold as the change in ASC resulting from adding major new resources, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more.

NorthWestern did not submit information on new resources with their ASC filing.

Table 1: ASC New Resource Additions

	FY 2006	FY 2007	FY 2008	FY 2009
Production Rate Base				
Plant Material and Supplies Rate Base				
Fuel Stock Rate Base				
Production O&M Expense				
Production Depreciation Expense				
Purchased Power Expense				
Production Property Tax				

Transmission Rate Base				
Transmission Depreciation Rate Base				
Transmission O&M Expense				
Transmission Contracts Expense				
Transmission Property Tax Expense				

(Expected) Annual Generation (MWh)				

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining NorthWestern's forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and NorthWestern's ASCs published in the July 8, 2008 report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and NorthWestern's ASCs as appropriate and as a result of NorthWestern's comments to the July 8, 2008 report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and NorthWestern's ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: Draft FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	$324,610,587	$341,935,535	$361,163,563	$381,860,346	$403,943,292
Transmission	49,239,878	47,983,943	46,750,169	45,473,552	44,220,494
NLSL Resource Cost	0.00	0.00	0.00	0.00	0.00
(Less) NLSL Costs	0	0	0	0	0
Contract System Cost	**$373,850,465**	**$389,919,478**	**$407,913,733**	**$427,333,898**	**$448,163,785**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	6,334,276	6,542,040	6,756,619	6,978,236	7,207,122
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net of NLSL)	6,334,276	6,542,040	6,756,619	6,978,236	7,207,122
Distribution Losses	510,787	527,540	544,844	562,715	581,172
Contract System Load	**6,845,062**	**7,069,580**	**7,301,463**	**7,540,951**	**7,788,294**

AVERAGE SYSTEM COST

ASC ($/MWh)	**$54.62**	**$55.15**	**$55.87**	**$56.67**	**$57.54**

Table 2: Revised FY 2009-2013 ASC Summary – August 4, 2008

Date (mid-year)	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	$325,462,219	$342,907,833	$362,295,357	$383,143,603	$405,390,416
Transmission	49,239,878	47,983,943	46,750,169	45,473,552	44,220,494
NLSL Resource Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00
(Less) NLSL Costs	0	0	0	0	0
Contract System Cost	**$374,702,097**	**$390,891,776**	**$409,045,526**	**$428,617,155**	**$449,610,909**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	6,334,276	6,542,040	6,756,619	6,978,236	7,207,122
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net of NLSL)	6,334,276	6,542,040	6,756,619	6,978,236	7,207,122
Distribution Losses	510,787	527,540	544,844	562,715	581,172
Contract System Load	**6,845,062**	**7,069,580**	**7,301,463**	**7,540,951**	**7,788,294**

AVERAGE SYSTEM COST

ASC ($/MWh)	**$54.74**	**$55.29**	**$56.02**	**$56.84**	**$57.73**

Table 2: Final FY 2009-2013 ASC Summary – September 11, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	$325,602,601	$343,066,995	$362,474,784	$383,344,870	$405,615,201
Transmission	49,773,010	48,305,130	46,859,814	45,371,968	43,907,962
NLSL Fully Allocated Cost ($/MWh)	0	0	0	0	0
(Less) NLSL Costs	0	0	0	0	0
Contract System Cost	**$375,375,611**	**$391,372,125**	**$409,334,598**	**$428,716,838**	**$449,523,163**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	6,334,276	6,542,040	6,756,619	6,978,236	7,207,122
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net of NLSL)	6,334,276	6,542,040	6,756,619	6,978,236	7,207,122
Distribution Losses	510,787	527,540	544,844	562,715	581,172
Contract System Load	**6,845,062**	**7,069,580**	**7,301,463**	**7,540,951**	**7,788,294**

AVERAGE SYSTEM COST

ASC ($/MWh)	**$54.84**	**$55.36**	**$56.06**	**$56.85**	**$57.72**

VI. BPA STATEMENT

This ASC determination is BPA's best estimate of NorthWestern's FY 2009 ASC based on the information and data provided from NorthWestern during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination, FY 2009. This determination is made solely for purposes of providing estimated FY 2009 ASCs for use in the development of BPA's FY 2009 power rates in BPA's WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such review will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance to the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System Cost of NorthWestern for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The amended Appendix 1 Filing and Forecast Model, and NLSL assessment used to calculate NorthWestern's ASCs can be viewed at BPA ASC website: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

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FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

PacifiCorp

Docket Number: PA-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

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TABLE OF CONTENTS

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I. FILING DATA

Utility	Parties to the Filing
PacifiCorp 825 NE Multnomah, Suite 2000 Portland, Oregon 97232	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
Production Cost	$863,127,579	$ 866,277,276	$841,461,476	$842,165,605
Transmission Cost	$187,309,496	$ 185,057,676	$174,610,936	$174,610,934
(Less) New Large Single Load Costs		$15,529,887	$16,964,577	$16,964,577
Total Contract System Cost	1,050,437,075	$1,035,805,065	$999,107,835	$999,811,962
Total Retail Load (MWh)	21,409,663	21,409,637	21,409,637	21,409,637
(Less) New Large Single Load	0	342,068	342,068	342,068
Total Retail Load (Net NLSL)	21, 409,663	21,067,569	21,067,569	21,067,569
Plus Distribution Losses	1,070,482	1,747,026	573,778	573,778
Total Contract System Load (MWH)	22,480,119	22,814,595	21,641,347	21,641,347
FY 2006 Base Period ASC ($/MWh)	$46.73	$45.40	$46.17	$46.20

Note: The "As Amended" values, as reported in the July 8, 2008 Draft Report, were incorrect. The corrected values are included in the above table.

B. FY 2009 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**$49.36**	**$47.94**	**47.98**

C. FY 09 (Exchange Period) ASC with New Resource Additions ($/MWh)

DRAFT - FY 2007-2009 New Resource Additions - See Table 1 in Section III.C for details

Resource	Lake Side Capital Building	Group 1	CCCT Plant West	Group 3	Group 4
Delta*	1.88	1.47	1.22	1.15	0.65

* Base ASC is $49.36/MWh. The Delta is the differential between the additions of each of the five resource groups starting with the Base ASC.

REVISED - FY 2007-2009 New Resource Additions - See Table 1 in Section III.C for details

Resource	Lake Side Capital Building	Group 1	CCCT Plant West	Group 3	Group 4
Delta*	0.81	1.20	0.19	0.89	0.45

* Base ASC is $ 47.94/MWh. The Delta is the differential between the additions of each of the five resource groups starting with the Base ASC.

FINAL - FY 2007-2009 New Resource Additions - See Table 1 in Section III.C for details

Resource	Lake Side Capital Building	Group 1	CCCT Plant West	Group 3	Group 4
Delta*	0.83	1.26	0.33	0.93	0.48

* Base ASC is $ 47.98/MWh. The Delta is the differential between the additions of each of the five resource groups starting with the Base ASC.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. See 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging Utilities agreed to a number of termination agreements that provided for payments to each Utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing Utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

For more information regarding the proposed 2008 ASCM, refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. ASC Determination Process Guidelines and Expedited Review Process

The purpose of BPA's expedited review process is to estimate exchanging Utilities' ASCs for FY 2009 that could be noticed by the Administrator and incorporated into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding rely on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance to the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1.
The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a base period ASC determination, BPA used the ASC Forecast model, an excel based spreadsheet, to escalate the base year ASC forward to the effective rate period, FY 2009 (October 1, 2008 through September 30, 2009). The base year and forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capitol (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1 to determine the Utility's return on investment.

IOUs use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For COUs, the rate of return is equal to the COU's weighted cost of debt.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as described above. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items.

<u>Contract System Costs</u>:
The Contract System Cost is defined as the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Loads:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any new large single load (NLSL).

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Off-System Sales

The Purchased Power is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1, pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A new large single load (NLSL) is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro rata basis using salary and wage data for production, transmission, and distribution/other functions included in the Utility's most recently filed Form 1. For consumer-owned utilities, comparable data is used based on the cost of service study used as the basis for retail rates at the time of review.

D. ASC Forecast

The Base Period ASC is applied to an Excel-based forecasting model to escalate the Base Year ASC data forward to the Exchange Period. For purposes of the expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Costs

Forecast Contract System Costs (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5%. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of any major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of the major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. Identification and Analysis of Issues from the May 7, 2008 ASC Appendix 1 Filing

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPAs ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Costs and codes filed on May 7, 2008 by PacifiCorp, and as amended following review and evaluation by BPA. The explanations for BPAs changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base

1. **302 Franchise & Consent**

   Direct Analysis requires justification of the cost allocations to Production or Transmission

   a. Statement of Issue: In the May 7th filing, PacifiCorp directly assigned this account to Production.

   b. Statement of Facts: The proposed ASCM permits direct analysis only for specified accounts. The ASCM contains default functionalization methods in the absence of direct analysis where appropriate. BPA will not allow Utilities to use a combination of direct analysis and a prescribed functionalization method for the same account. Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility through direct analysis, can justify how the ratio adequately reflects the functional nature of the costs included in any account or cost item being functionalized by the ratio.

c. PacifiCorp's Response to the Issue: The Revised Protocol Methodology allows only the following two methods of allocation to be used for this account (Page 13 of Appendix B).

302 Franchise & Consent

Distribution	S
Production, Transmission	SG

A detailed description of the assets in this account has previously been provided in response to BPA Data Request 4. See Tab – Electric Plant in Service. Except for $1 million of rate base assigned directly to Idaho, costs in these accounts are allocated on the SG factor and have been allocated to production since they are the costs associated with acquiring new hydro electric licenses. (The Company has updated the filing to reflect the $1 million assigned incorrectly to production rather than distribution). Of the total of $118 million in this account, $80 million is related to the relicensing of the North Umpqua project, $14 million to the Grace Hydroelectric plant, $4 million to the Condit Hydroelectric plant and the remaining to smaller hydroelectric projects.

d. Analysis of Position and Decision: PacifiCorp provided sufficient information to support the direct analysis of this account.

2. **Account 303, Intangible Plant Miscellaneous**

a. Statement of Issue: In the May 7th filing, PacifiCorp directly functionalized this account without showing the basis of the direct assignments.

b. Statement of Facts: The proposed ASCM permits direct analysis only for specified accounts. The ASCM contains default functionalization methods in the absence of direct analysis where appropriate. BPA will not allow Utilities to use a combination of direct analysis and a prescribed functionalization method for the same account. Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if Utility through direct analysis, can justify how the ratio adequately reflects the functional nature of the costs included in any account or cost item being functionalized by the ratio.

c. PacifiCorp's Response to the Issue: Account 303 – Intangible Plant. The Revised Protocol Methodology allows the following methods of allocation to be used for this account (Page 13 of Appendix B).

303 Miscellaneous Intangible Plant

Distribution	S
Remaining Steam Plants	SG
Peaking Plants	SSGCT
Cholla	SSGCH
Pacific Hydro	SG
East Hydro	SG
Transmission	SG
Customer Related	CN
General	SO

A detailed description of the assets in this account is included in the tab "Account 303" included as part of the ASC filing.

This account lists 118 assets totaling $548 million. Of these assets, $86 million are allocated on the SG or SE factor and have been assigned to production or transmission as appropriate as follows.

<u>Production</u>

Deer Creek Intangible Assets
Craig Plant Maintenance Management System
Caiso Energy Management Analysis
Rogue River Hydroelectric Intangibles
Improvements to Plant Owned By James River
Gadsby Intangible Assets
Eagle Point Hydro Assets
Swift 2 Improvements
Bear River-Settlement Agreement
Apogee - Energy Exchange Program
Link River Dam Rights
Hayden – Vibration Software
Steam Plant Intangible Assets
Commercial & Trading Hedge Accounting Standards

<u>Transmission</u>

Transmission Intangible Assets
Transmission Wholesale Billing System
Idaho Transmission Customer Owned

The remaining $462 million consists of various computer hardware and software assets. Two assets dwarf the remaining assets – the Company's accounting software – SAP ($159 million) and Customer Service System

($102 million) which support all areas of the Company and have been allocated on the PTD factor.

Of the remaining $201 million in assets, the following assets have been allocated to Distribution

Distribution Automation Pilot Project
Miscellaneous Projects – Idaho, Oregon, Washington, Wyoming & Utah

The following assets have been allocated to **Production**

Fuel Management System
Energy Management System
Heat Rate Performance Software
Retail Energy Services Tracking
Energy Commodity System Software
2002 GRID Net Power Costs Modeling
Mid Office Improvement Project
SB1149 - Accommodate CSS and MDM to SB1149
C&T Official Record Information System
APOGEE – Energy Exchange System
K2 - KWI Commercial Risk System
Electronic Tagging System - Merchant

The following assets are allocated **TD**

Automate Pole Card System
Salt Lake SCADA System
Pole Attachment Management System
Ranger EMS/SCADA System

Of the remaining assets, none can be clearly assigned to production, transmission, distribution or TD as they support all of these areas and the Company has allocated then on the PTD factor.

d. Analysis of Position and Decision: PacifiCorp provided information to support the direct analysis of this account.

3. **Account 302 & 303 – Accumulated Amortization of Intangible Plant**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized the amortization of 302 Franchise & Consent to Production. In addition, account 303 was functionalized using Direct Analysis.

b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production. What is the regulatory treatment of this account?

c. PacifiCorp's Response to the Issue: The accumulated amortization of the rate base in these accounts follows the treatment accorded the rate base described above.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the functionalization of Account 302 & 303 – Accumulated Amortization of Intangible Plant

4. **Account 399– Other Tangible Property**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 399 "Other Tangible Property" to Production without adequate support for the Direct Analysis.

b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production, Transmission or Distribution. Direct Analysis requires justification of the cost allocations to Production

c. PacifiCorp's Response to the Issue: This account includes only "Plant used in Mining Activities" and the Company includes it in rate base in regulatory proceedings and earns a return on the asset. A detailed description of the items in the account is found on page 450.1 supporting page 206 – 207, line 97. The Company also owns part of the Jim Bridger and Trapper mines. All costs associated with these mines, except for a return on the rate base, are included as fuel costs. PacifiCorp adds this investment on this line. (Backup – 2006 Results of Operations pages 8.2 & 8.3)

d. Analysis of Position and Decision: PacifiCorp provided sufficient information to support the direct analysis of this account.

5. **Account 114 Acquisition Adjustments**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 114 Acquisition Adjustments to Production without adequate support for the Direct Analysis.

b. Statement of Facts: The functionalization of Account 114 Acquisition Adjustments requires a Direct Analysis, which requires justification of the cost allocations to Production, Transmission and Distribution.

c. PacifiCorp's Response to the Issue: A description of the assets in this account has previously been provided in response to BPA Data Request 4. See Tab – Miscellaneous Rate Base. The costs included in this account (all allocated on the SG allocation factor) are related to the Company's purchase of the Craig, Hayden, Cholla and Wyodak plants. They are allocated to the production function and the Company includes the asset in rate base in regulatory proceedings and earns a return on the asset.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the functionalization of Account 114 Acquisition Adjustments to Production.

6. **Account 115 – Amortization of Acquisition Adjustment**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized the Accumulated Amortization to Production without adequate support for the Direct Analysis.

b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production The accumulated amortization of the rate base in these accounts follows the treatment accorded the rate base described above.

c. PacifiCorp's Response to the Issue: The amortization of the rate base in this account follows the treatment accorded the rate base described above. The total is less than the production allocation because of an error in the calculation of the Idaho amortization. The Company has corrected this error in this filing of its ASC.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the functionalization of Account 115 Accumulated Amortization of Acquisition Adjustments to Production.

7. **Account 182.3 – Other Regulatory Assets**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 182.3 Other Regulatory Assets using Direct without adequate support for the Direct Analysis.

b. Statement of Facts: The functionalization of Account 182.3 Other Regulatory Assets requires a Direct Analysis, which requires justification of the cost allocations to Production, Transmission and Distribution. What is the regulatory treatment of this account and components?

c. PacifiCorp's Response to the Issue: The Company begins with the assumption that these assets can only be included in the ASC calculation if the State Regulatory Agencies have approved them for recovery in a rate making proceeding. The TAB – Regulatory Assets includes only those assets included in rate base in a regulatory proceeding. They total $81 million compared to $1.396 billion shown on the FERC Form One.

The following assets have been allocated to **Production**

182.300	Conservation
182.302	Direct Access – California
182.304	Direct Access - Oregon
182.392	Conservation
182.393	Conservation
182.394	Conservation
182.396	Conservation
182.3993	Cholla Transaction Costs
182.3994	Cholla Transaction Costs
182.3995	Cholla Transaction Costs
182.3999	DSM Regulatory Assets – Accruals

The following assets have been allocated **PTD**

182.391	Environmental Remediation
182.387	FAS 87/88 Utah

The following assets with 182.3990 have been allocated **Production**

187003	Retail Access Project – Oregon
187004	Energy Trust
187050	Cholla Transaction Costs
187051	Washington Colstrip #3 Regulatory Asset
187058	Trail Mountain Mine Closure Costs
187070	Trail Mountain Mine Costs - Deseret Settlement
187107	Glenrock Mine Excluding Reclamation - UT
187111	Noell Kempf Cap - UT
187112	P&M Strike Amort - UT
187903	Wyoming - Deferred Excess Net Power Costs
187904	Idaho - Deferred Net Power Costs
187906	Def Excess NPC - Oregon Ue116 Bridge
187907	Or Ue134 Power Cost

The following assets with 182.3990 have been allocated **Transmission**

187081	RTO Grid West N/R - OR
187082	RTO Grid West N/R - WY

The remaining assets with 182.3990 have been allocated PTD as they support all functional areas. The largest two are assets are 1998 – Early Retirement (Oregon) and May 2000 Transition Costs (Oregon). These comprise over 80% of Account 182.399 not directly assigned to Production, Transmission and Distribution.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the Direct Analysis of Account 182.3 Regulatory Assets.

8. **Account 186 – Miscellaneous Deferred Debits**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 186 – Miscellaneous Deferred Debits to production using Direct Analysis without providing sufficient support for the Direct Analysis.

b. Statement of Facts: The functionalization of Account 186 – Miscellaneous Deferred Debits requires a Direct Analysis, which requires justification of the cost allocations to Production, Transmission and Distribution. What is the regulatory treatment of this account and components?

c. PacifiCorp's Response to the Issue: The Company begins with the assumption that those assets can only be included in the ASC calculation if the State Regulatory Agencies have approved them for recovery in a rate making proceeding. The TAB – Deferred Debits includes only those assets included in rate base in a regulatory proceeding. They total $42 million compared to $58 million shown on the FERC Form One. The Company believes all the Miscellaneous Deferred Debits are production related.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the Direct Analysis of A Account 186 – Miscellaneous Deferred Debits

9. **Account 253 – Miscellaneous Deferred Credits**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 253 Miscellaneous Deferred Credits using Direct Analysis without providing sufficient support for the Direct Analysis.

b. Statement of Facts: The functionalization of Account 186 – Miscellaneous Deferred Debits requires a Direct Analysis, which requires justification of the cost allocations to Production, Transmission and Distribution.

c. PacifiCorp's Response to the Issue: The Company begins with the assumption that those liabilities can only be included in the ASC calculation if the State Regulatory Agencies have approved them for recovery in a rate making proceeding. The TAB – Miscellaneous Rate Base includes only those liabilities included in rate base in a regulatory proceeding. They total $16 million compared to $62 million shown on the FERC Form 1. Within this account, liabilities allocated SE or SG and Oregon DSM loans are production related. Unearned Joint Pole Use revenue allocated directly to a state is distribution related. The remaining liability, a software liability is assigned PTD.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the Direct Analysis of Account 253 - Miscellaneous Deferred Credits.

10. **Account 253 – Miscellaneous Deferred Credits**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 254 Other Regulatory Liabilities using Direct Analysis, without sufficient justification for the cost assignments.

b. Statement of Facts: The functionalization of Account 186 – Miscellaneous Deferred Debits requires a Direct Analysis, which requires justification of the cost allocations to Production, Transmission and Distribution.

c. PacifiCorp's Response to the Issue: The Company begins with the assumption that those liabilities can only be included in the ASC calculation if the State Regulatory Agencies have approved them for recovery in a rate making proceeding. The TAB – Miscellaneous Rate Base includes only those liabilities included in rate base in a regulatory proceeding. They total $4 million compared to $109 million shown on the FERC Form One. Within this account, the Property Insurance reserve is assigned PTD. The Trojan Nuclear Plant liability is assigned to Distribution.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information for the Direct Analysis of this account. The Functionalization of separate sub accounts will be addressed in the October 1, 2008 filing.

11. **Account 244 - Long-Term Portion of Derivative Instrument Liabilities**

a. Statement of Issue: Long-Term Portion of Derivative Instrument Liabilities appears in two places on the June 6, 2008 filing template.

b. Statement of Facts: Long-Term Portion of Derivative Instrument Liabilities should only appear in the Current and Accrued Liabilities Section.

c. Analysis of Position and Decision: Given Long-Term Portion of Derivative Instrument Liabilities functionalization to distribution, the adjustment for the double counting will have no impact on the ASC.

12. **Functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio**

a. Statement of Issue: Correct functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio

b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

c. Analysis of Position and Decision: The functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from distribution to PTD in the ASC Template

SCHEDULE 1A: Cash Working Capital – no changes

SCHEDULE 2: Capital Structure and Rate of Return – no changes

SCHEDULE 3: Expenses

1. **Functionalization of Customer Service and Informational**

a. Statement of Issue: Correct functionalization of Customer Service and Informational in the Labor Ratio

b. Statement of Facts: Customer Service and Informational in the Labor Ratio should have been functionalized to Distribution rather than Direct ASC Template.

c. PacifiCorp's Response to the Issue: Four types of costs are contained in this account: Expense associated with current conservation programs (DSM DIRECT); the amortization of previously capitalized conservations programs (DSM AMORT); Customer Service (CUST SERV); and Customer Assistance (CUST ASSIST EXP and CUST ASST EXP – GENL). The first two cost categories are production costs. The last two cost categories have been assigned to the distribution function. A detailed description of the expense in this account is included in the tab "Account 908" included as part of the ASC filing. The Company recovers these expenses by including them in its revenue requirement in regulatory proceedings.

d. Analysis of Position and Decision: PacifiCorp identified DSM related costs within Account 908, with the correct functionalization to Production. The remainder of this account was functionalized to Distribution.

2. **Oregon Public Purpose Charge**

a. Statement of Issue: In its May 7th filing, PacifiCorp the Oregon Public Purpose Charge using Direct Analysis, without sufficient justification for the cost assignments.

b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production, Transmission or Distribution

c. PacifiCorp's Response to the Issue: ORS 757.612 specifies that the public purpose charge be used for cost-effective conservation and market transformation, the above-market costs of renewable energy resources, low-income weatherization. In addition school districts may use the funds allocated to them to fund energy audits, weatherization, energy efficiency, energy conservation education programs, purchasing energy from environmentally focused sources and investing in renewable energy sources. All these are production related and the Company has assigned that portion of the public purpose charge to production. The final portion of the Public Purpose Charge is transferred to Housing and Community Services and has been assigned to distribution. The detailed accounting for 2006 has previously been provided in response to BPA Data Request 6.

d. Analysis of Position and Decision: The functionalization of the Oregon Public Purpose Charge will be addressed in the October 1, 2008 Filing.

3. **Account 404 – Amortization of Intangible Assets (302 & 303)**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized the amortization of 302 Franchise & Consent to Production. In addition, account 303 was functionalized using Direct Analysis.

b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production.

c. PacifiCorp's Response to the Issue: The amortization of the rate base in these accounts follows the treatment accorded the rate base described above.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the functionalization of Account 302 & 303 – Amortization of Intangible Plant

SCHEDULE 3A: Taxes – no changes

SCHEDULE 3B: Other Included Items – no changes

1. **Account 421 - Miscellaneous Non-operating Income**

   a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 421 – Miscellaneous Non-operating Income to Distribution.

   b. Statement of Facts: Account 421– Miscellaneous Non-operating Income to Distribution requires a Direct Analysis with a default functionalization to Production. PacifiCorp directly functionalized this account to Distribution without the required analysis.

   c. PacifiCorp's Response to the Issue: Two cost categories are included in this account. The vast majority ($475 million) of the total amount, $480 million is related to FAS 133 Unrealized Gains. Consistent with the treatment of unrealized gains recorded on the balance sheet which have been assigned to distribution, the income associated with them has also been assigned to distribution. The second category is miscellaneous non-operating income which has also been assigned to distribution as it is unrelated to the utility operations of the Company. A detailed description of the expense in this account is included in the tab "Account 421" included as part of the ASC filing.

   d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the Direct Analysis of Account 421 – Miscellaneous Non-Operating Income.

2. **Account 456 – Other Electric Revenue**

   a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 456 – Miscellaneous Non-operating Income using Direct Analysis, without adequate support for the functionalization.

   b. Statement of Facts: Account 456 – Miscellaneous Non-operating Income is to be functionalized using Direct Analysis with a default functionalization to Production.

   c. PacifiCorp's Response to the Issue: Account 456.1, Wheeling Revenue is assigned to Transmission. Accounts 456.20, 456.23, 456.24 & 456.25 are distribution related assigned directly to each state. Accounts 456.22 and 456.4 are related to DSM tariff revenues and the proposed ROD states that they should not be included as an expense in ASC filings – the Company as therefore assigned them to distribution. Account 456.21 – Use of facilities should be assigned TD and Accounts 456.26, 456.266, 456.65 & 456.66 are wheeling related and are assigned to transmission. This account is included in regulatory proceedings.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the Direct Analysis of Account 456 – Miscellaneous Non-operating Income.

SCHEDULE 4: Average System Cost

1. **Distribution Loss:**

a. Statement of Issue: In its filing, PacifiCorp used a 5% Distribution Loss Factor in determination of its ASC.

b. Statement of Facts: The May 7th filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years. Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

c. PacifiCorp's Response to the Issue: The Company will follow the proposed ROD and either provide a loss study or follow the methodology described by BPA in the ROD.

d. Analysis of Position and Decision: For purposes of the expedited filing, BPA completed the Distribution Loss Factor outlined in the ASCM ROD, Section 4.10.5. PacifiCorp's Distribution Loss Factor has been set at 8.16%.

2. **Contract System Loads: New Large Single Load (NLSL)**

a. Statement of Issue: The May 7th Appendix 1 filing did not require and therefore did not include information on NLSL MWh. BPA now requires this data to be included in the determination of a Utility's ASC.

b. Statement of Facts: PacifiCorp submitted data identifying one potential NLSL usage of 342,068 MWh. BPA determined this load by the evaluation of PacifiCorp provided data.

c. Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit costs of servicing an NLSL to be included in the calculation of a Utility's ASC and, therefore, BPA removed the NLSL and associated costs from the Appendix 1 amended filing. The results are noted in Schedule 4 of the amended Appendix 1 filing.

3. **Contract System Costs: New Large Single Load (NLSL) Costs**

a. Statement of Issue: The May 7th filing Appendix 1 template did not require and therefore did not include information on NLSL costs. BPA now requires this data to be included in the determination of a Utility's ASCs.

b. Statement of Facts: BPA determined the cost of serving the potential NLSL using the fully allocated cost of all escalated base period post-September 1, 1979, resources and major resource additions and long-term power purchases (5 years or longer contracts) used to determine Exchange Period ASCs as outlined in the ASCM ROD, section 4.5. In addition, BPA will not allow a Utility's ASC to increase as a result of excluding the costs of resources used to serve NLSLs.

c. Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit costs of servicing an NLSL to be included in the calculations of a Utility's ASC and therefore, BPA removed the NLSL and associated costs from the Appendix 1 amended filing. The results are noted in Schedule 4 of the amended Appendix 1 filing.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – no changes

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes

SUPPORTING DOCUMENTATION: Labor Ratios

1. **Maintenance of General Plant (GPM) Ratio: Miscellaneous Equipment**

   a. Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

   b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

   c. Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

B. Identification and Analysis of Issues from Comments to the July 8, 2008 ASC Draft Report

SCHEDULE 1: Plant Investment/Rate Base

1. **Account 218 – Accumulated Amortization of Intangibles**

   a. Statement of Issue: Functionalization of costs.

   b. Statement of Facts: In the May 7th filing, the sum of production, transmission, and production did not equal the total.

   c. PacifiCorp's Response to the Issue: In PacifiCorp's July 24, 2008 Revised Comments, PacifiCorp identified the problem and made the appropriate adjustments.

   d. Analysis of Position and Decision: BPA agreed with PacifiCorp's adjustments and made the appropriate adjustment.

2. **Account 182.3 – Regulatory Assets**

   a. Statement of Issue: Functionalization of costs.

   b. Statement of Facts: In the May 7th filing, the sum of production, transmission, and production did not equal the total.

   c. PacifiCorp's Response to the Issue: In PacifiCorp's July 24, 2008 Revised Comments, PacifiCorp Identified the problem and made the appropriate adjustments

d. Analysis of Position and Decision: BPA agreed with PacifiCorp's adjustments and made the appropriate adjustment.

3. **Account 186 – Miscellaneous Deferred Debits**

a. Statement of Issue: Functionalization of costs.

b. Statement of Facts: In the May 7th filing, the sum of production, transmission, and production did not equal the total.

c. PacifiCorp's Response to the Issue: In PacifiCorp's July 24, 2008 Revised Comments, PacifiCorp Identified the problem and made the appropriate adjustments

d. Analysis of Position and Decision: BPA agreed with PacifiCorp's adjustments and made the appropriate adjustment.

4. **Account 253 – Other Deferred Credits**

a. Statement of Issue: Functionalization of costs.

b. Statement of Facts: In the May 7th filing, the sum of production, transmission, and production did not equal the total.

c. PacifiCorp's Response to the Issue: In PacifiCorp's July 24, 2008 Revised Comments, PacifiCorp identified the problem and made the appropriate adjustments.

d. Analysis of Position and Decision: BPA agreed with PacifiCorp's adjustments and made the appropriate adjustment.

5. **Account 254 – Other Regulatory Liabilities**

a. Statement of Issue: Functionalization of costs.

b. Statement of Facts: In the May 7th filing, the sum of production, transmission, and production did not equal the total.

c. PacifiCorp's Response to the Issue: In PacifiCorp's July 24, 2008 Revised Comments, PacifiCorp identified the problem and made the appropriate adjustments.

d. Analysis of Position and Decision: BPA agreed with PacifiCorp's adjustments and made the appropriate adjustment.

SCHEDULE 1A: Cash Working Capital – no changes from July 8, 2008 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from July 8, 2008 report

SCHEDULE 3: Expenses

1. **Account 935 - Maintenance of General Plant**

a. Statement of Issue: Expenses reported

b. Statement of Facts: Total company expenses were reported for Oregon Washington, and Idaho.

c. PacifiCorp's Response to the Issue: In PacifiCorp's July 24, 2008 Revised Comments, PacifiCorp identified the problem and made the appropriate adjustments to reflect the actual costs for Oregon Washington, and Idaho.

d. Analysis of Position and Decision: BPA agreed with PacifiCorp's adjustments and made the appropriate adjustment.

SCHEDULE 3A: Taxes – no changes from July 8, 2008 report

SCHEDULE 3B: Other Included Items – no changes from July 8, 2008 report

SCHEDULE 4: Average System Cost

2. **Distribution Loss:**

a. Statement of Issue: In its filing, PacifiCorp used a 5% Distribution Loss Factor in determination of its ASC.

b. Statement of Facts: The May 7th filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years. Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5. For purposes of the expedited filing, BPA completed the Distribution Loss Factor outlined in the ASCM ROD, Section 4.10.5. PacifiCorp's Distribution Loss Factor has been set at 8.16%.

c. PacifiCorp's Response to the Issue: In PacifiCorp's July 24, 2008 Revised Comments, PacifiCorp provided a loss study based on 2003 loss study. PacifiCorp proposed a distribution loss factor of 2.68 %.

d. Analysis of Position and Decision: BPA, per the ASCM, accepts PacifiCorp's 2003 loss study as the basis for calculation distribution losses. BPA has not had the time to assess the accuracy of the study. BPA will conduct a detailed review of any study PacifiCorp provides in the October 1 ASC filing.

3. **Contract System Costs: New Large Single Load (NLSL) Costs**

a. Statement of Issue: Change in BPAs estimate of the costs associated with an NLSL

b. Statement of Facts: BPA originally estimated that PacifiCorp's costs associate with an NLSL was $45.40 per MWh.

c. Analysis of Position and Decision: BPAs current estimate of the PacifiCorp's costs associate with an NLSL is $49.59 per MWh

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale –

a. Statement of Issue: Treatment of the Residential Exchange Settlement Payment in the ASC Template.

b. Statement of Facts: The Residential Exchange Settlement Payment was erroneously included in Account 555 – Purchased Power as a credit and then included as a separate line item (REP reversal) in the ASC calculation.

c. Analysis of Position and Decision: The Residential Exchange Settlement Payment is not an exchangeable cost or credit. BPA therefore removed the Residential Exchange Settlement Payment (credit) from Account 555 – Purchased Power, which increased purchased power by the amount of the credit. BPA simultaneously removed the REP reversal as a separate line item in the ASC template.

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes from July 8, 2008 report

SUPPORTING DOCUMENTATION: Labor Ratio– no changes from July 8, 2008 report

C. Identification and Analysis of Issues from comments to the August 4, 2008 ASC Draft Report

SCHEDULE 1: Plant Investment/Rate Base–

1. For Account 108, line item "**Capital Leases - Common Plant"** and **In-Service: Depreciation of Common Plant.**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

   b. Analysis of Position and Decision: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments** (**Electric)**, Account 114, line 92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4 2008 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4 2008 report

SCHEDULE 3: Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/Rate Base*** **(Acquisition Adjustments (Electric)**, (cell E92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses:

   b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4 2008 report

SCHEDULE 3B: Other Included – no changes from the August 4 2008 report

SCHEDULE 4: Average System Cost - – no changes from the August 4 2008 report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

   a. Statement of Issue: For Labor Ratio Input: line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

   b. Analysis of Position and Decision: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908: all exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

D. Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC are allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that Utility's retail load during the BPA rate period. The change in ASC must meet the materiality threshold as the change in ASC resulting from adding major new resources, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more. BPA determined a change in PacifiCorp's ASC using the methods as described in the ASCM ROD, section 4.2.10.

Table 1 below identifies the New Resource Additions information provided from PacifiCorp. Tables 1, ASC New Resource Additions and Table 2, FY 2009-2013 ASC Summary, summarize the results.

Table 1: ASC New Resource Additions

		6/30/2007	8/1/2008	9/14/2008	12/31/2008	6/1/2009
		Lake Side Capital Building	Group 1	CCCT Plant West (525 MW)	Group 3	Group 4
		NG	Other	NG	Other	Other
Other Production Plant						
Other Production	340-346	$138,979,231	$318,455,478	$128,123,754	$247,147,430	$159,760,358
Fuel Stock	151					
Plant Materials and Operating Supplies	154					
EPA Allowances	158.1-158.2					
Other Expense						
Other Power - Fuel	547	$64,661,215		$59,610,616		
Other Power - Operations (Excluding 547 - Fuel)	546-550					
Other Power - Maintenance	551-554	$2,278,366	$4,387,932	$2,100,406	$4,961,381	$3,159,328
Property Insurance	924	$418,246	$958,365	$385,578	$743,770	$480,785
Depreciation	403	$3,660,222	$10,998,583	$3,374,327	$10,003,894	$6,466,690
Firm Sales for Resale ($)	447					
Firm Sales for Resale (MWh)						
Expected Annual Generation (MWh)		1,196,527	$367,629	1,103,068	$392,774	290,960
Property Taxes						

		6/30/2007	8/1/2008	9/14/2008	12/31/2008	6/1/2009
		Lake Side Capital Building	Group 1	CCCT Plant West (525 MW)	Group 3	Group 4
		NG	Other	NG	Other	Other
Production						
Total Production Property	262	$1,206,997	$2,765,700	$1,112,720	$2,146,409	$1,387,476

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining PacifiCorp's forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and PacifiCorp's ASCs published in the July 8, 2008 report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and PacifiCorp's ASCs as appropriate and as a result of PacifiCorp's comments to the July 8, 2008 report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and PacifiCorp's ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST ($)

Production	1,150,023,901	1,124,484,515	1112137282	1,112,029,163	1113257611
Transmission	179,212,567	177,629,054	176194438	174,796,728	173490803
NLSL Fully Allocated Cost ($/MWh)	57.97	56.50	55.52	55.12	54.73
(Less) NLSL Costs	19,828,379	19,327,715	18991028	18,853,328	18721359
Total Contract System Cost	1,309,408,089	1,282,785,854	1269340692	1,267,972,564	1268027055

CONTRACT SYSTEM LOAD (MWh)

Total Retail Load @ Meter	22,016,008	22,207,898	22,427,330	22,654,332	22,880,278
(Less) NLSL	342,068	342,068	342,068	342,068	342,068
Total Retail Load (Net or NLSL)	21,673,940	21,865,830	22,085,262	22,312,264	22,538,210
Distribution Loss	1,825,676	1,841,588	1,859,784	1,878,609	1,897,345
Total Contract System Load	23,499,616	23,707,418	23,945,046	24,190,873	24,435,555

AVERAGE SYSTEM COST

ASC ($/MWh)	**55.72**	**54.11**	**53.01**	**52.42**	**51.89**

Revised Table 2: FY 2009-2013 ASC Summary – August 4, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST ($)

Production	996,996,399	960,816,433	969,702,988	971,406,430	976,017,942
Transmission	169,573,533	167,697,323	165,983,195	164,307,492	162,713,832
NLSL Fully Allocated Cost ($/MWh)	57.96	55.66	55.58	55.07	54.63
(Less) NLSL Costs	19,825,602	19,039,861	19,013,752	18,837,860	18,688,195
Total Contract System Cost	1,146,744,330	1,109,473,896	1,116,672,431	1,116,876,062	1,120,043,578

CONTRACT SYSTEM LOAD (MWh)

Total Retail Load @ Meter	22,016,008	22,207,898	22,427,330	22,654,332	22,880,278
(Less) NLSL	342,068	342,068	342,068	342,068	342,068
Total Retail Load (Net or NLSL)	21,673,940	21,865,830	22,085,262	22,312,264	22,538,210
Distribution Loss	599,609	604,835	610,812	616,994	623,148
Total Contract System Load	22,273,549	22,470,665	22,696,074	22,929,258	23,161,358

AVERAGE SYSTEM COST

ASC ($/MWh)	**51.48**	**49.37**	**49.20**	**48.71**	**48.36**

Final Table 2: FY 2009-2013 ASC Summary – September 11, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST ($)

Production	1,001,429,090	964,635,860	972,845,032	973,829,991	977,745,929
Transmission	172,107,523	170,231,271	168,517,142	166,841,503	165,247,996
NLSL Fully Allocated Cost ($/MWh)	58.07	55.78	55.70	55.18	54.74
(Less) NLSL Costs	19,865,032	19,078,938	19,052,436	18,876,147	18,726,097
Total Contract System Cost	1,153,671,581	1,115,788,194	1,122,309,738	1,121,795,347	1,124,267,828

CONTRACT SYSTEM LOAD (MWh)

Total Retail Load @ Meter	22,016,008	22,207,898	22,427,330	22,654,332	22,880,278
(Less) NLSL	342,068	342,068	342,068	342,068	342,068
Total Retail Load (Net or NLSL)	21,673,940	21,865,830	22,085,262	22,312,264	22,538,210
Distribution Loss	590,029	595,172	601,052	607,136	613,191
Total Contract System Load	22,263,969	22,461,002	22,686,314	22,919,400	23,151,401

AVERAGE SYSTEM COST

ASC ($/MWh)	**51.82**	**49.68**	**49.47**	**48.95**	**48.56**

VI. BPA STATEMENT

This ASC determination is BPAs best estimate of PacifiCorp's FY 2009 ASC based on the information and data provided from PacifiCorp during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination for FY 2009. This determination is made solely for the purpose of providing estimated FY 2009 ASCs for use in the development of BPAs FY 2009 power rates in BPAs WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such reviews will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance with the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System of PacifiCorp for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The Final Appendix 1 Filing, Forecast Model and NLSL assessment used to calculate PacifiCorp's ASCs can be viewed at BPAs ASC website: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

Portland General Electric Company

Docket Number: PG-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

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TABLE OF CONTENTS

Section **Page**

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I. FILING DATA

Utility	Parties to the Filing
Portland General Electric Company 121 SW Salmon St. Portland, OR 97204	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	**July 8, 2008 As Amended**	**August 4, 2008 As Revised**	**Sept. 11, 2008 Final**
Production Cost	$932,953,681	$855,327,775	$780,278,890	$780,278,890
Transmission Cost	113,905,007	108,758,429	$108,758,429	$108,758,429
(Less) NLSL Costs	13,165,394	16,433,428	$15,957,669	$15,957,669
Contract System Cost	$1,033,693,293	$947,652,776	$873,079,649	$873,079,649
Total Retail Load (MWh)	18,432,527	18,432,527	18,432,527	18,432,527
(Less) NLSL	328,992	328,992	328,992	328,992
Total Retail Load (Net of NLSL)	18,103,535	18,103,535	18,103,535	18,103,535
Distribution Losses	986.333	868,172	868,172	868,172
Contract System Load	19,089,868	18,971,707	18,971,707	18,971,707
FY 2006 Base Period ASC ($/MWh)	**$54.15**	**$49.95**	**$46.02**	**$46.02**

B. FY 09 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**$52.16**	**$50.22**	**$50.49**

C. July 8, 2008 - FY 2009 ASC with New Resource Additions ($/MWh)

Resource	Port Westward	Biglow Canyon	Selective Water Withdrawal	Biglow Canyon 2
Delta*	$3.38	$1.36	$0.63	$2.00

* Base ASC is $52.16/MWh. The Delta is the differential between the additions of each of the four resource groups starting with the Base ASC.

D. August 4, 2008 Revised FY 2009 ASC with New Resource Additions ($/MWh)

FY 2007-2009 New Resource Additions - See Table1 in Section III.B for details

Resource	Port Westward	Biglow Canyon	Selective Water Withdrawal	Biglow Canyon 2
Delta*	$3.16	$1.35	$0.63	$1.99

* Base ASC is $50.22/MWh. The Delta is the differential between the additions of each of the four resource groups starting with the Base ASC.

E. September 11, 2008 – Final FY 2009 ASC with New Resource Additions ($/MWh)

Resource	Port Westward	Biglow Canyon	Selective Water Withdrawal	Biglow Canyon 2
Delta*	$3.13	$1.37	$0.60	$1.94

* Base ASC is $50.49/MWh. The Delta is the differential between the additions of each of the four resource groups starting with the Base ASC.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging Utilities agreed to a number of termination agreements that provided for payments to each Utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing Utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. ASC Determination Process Guidelines and Expedited Review Process

The purpose of BPA's expedited review process was to estimate exchanging Utilities' ASCs for FY 2009 that could be incorporated into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding relied on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance to the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1.

The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a Base Period ASC determination, BPA used the ASC Forecast model, an Excel-based spreadsheet, to escalate the Base Period ASC forward to the effective rate period, FY 2009 (October 1, 2008 through September 30, 2009). The Base Period and Forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1 to determine the Utility's return on investment.

IOUs use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For Consumer-Owned Utilities (COU), the rate of return is equal to the COU's weighted cost of debt times total rate base.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as outlined in the ASCM, Table 1. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items. The schedule also lists the load information, as defined below, and calculates the Utility's ASC.

<u>Contract System Cost</u>:
The Contract System Cost is the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Load:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any New Large Single Load(s) (NLSL).

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Sales for Resale

The Purchased Power is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1, pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A NLSL is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro rata basis using salary and wage data for Production, Transmission, and Distribution/other functions included in the Utility's most recently filed Form 1. For COUs, comparable data is used based on the cost of service analysis (COSA) study used as the basis for retail rates in effect during the Base Year filing.

D. ASC Forecast

The Base Period ASC is an Excel-based forecasting model used to escalate the Base Period ASC data forward to the Exchange Period. For purposes of the expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Cost

Forecast Contract System Cost (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5%. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of any major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of the major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. Identification and Analysis of Issues from the May 7, 2008 ASC Appendix 1 Filing

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Cost and Contract System Load filed on May 7, 2008 by Portland General Electric Company (PGE), and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base: - No Changes

SCHEDULE 1A: Cash Working Capital: – Changed due to changes from in Schedule 3

SCHEDULE 2: Capital Structure and Rate of Return: - No Changes

SCHEDULE 3: Expenses:

1. **REP Reversal:** PGE included the difference between the mark-to-market value of the purchase of BPA power at the RL rate and the cost of the RL power in its ASC filing as an REP Reversal. The BPA-PGE RL purchase power contract expired in September of 2006 ASC Filing.

    a. Statement of Issue: Should the mark-to-market value of the PGE purchase of power at the RL rate be included in ASC on Schedule 3.

    b. Statement of Facts: In the May 7th filing, PGE included mark-to-market value of the power it purchased from BPA at the RL rate. This contract was a part of BPA's REP Settlement Agreements that were invalidated by the 9th Circuit Court of Appeals in 2007. Under the REP Settlement agreement, BPA sold power to PGE at a rate far below what PGE could purchase the power for in the market. The difference between the value of the RL purchase at market prices and the cost of the power from BPA was distributed to PGE residential and small customers. The amount distributed to PGE customers was reported on Schedule 3 as REP Reversal.

c. Analysis of Position and Decision: BPA made two adjustments to PGE's ASC filing to remove the effects of the REP Settlement Agreements. First, the REP reversal amount will be removed from Schedule 3 because the benefits distributed by PGE to its eligible customers are not an expense for ASC purposes. Second, because the purchased power contract between BPA and PGE associated with the REP Reversal expired in September of 2006, BPA will remove the MWh and cost for the RL purchase included in Account 555, Purchased Power in the 2009 ASC Forecast Model. The RL purchase will be replaced with purchases at the market price of power. This adjustment will show up as a negative in the Resource Additions table. Despite its language in the July 9, 2008 Draft Report that it made the above described adjustment, BPA did not make this adjustment in that Report, but has made it this version of PGE's ASC Report.

SCHEDULE 3A: Taxes: No Changes

SCHEDULE 3B: Other Included Items: No Changes

SCHEDULE 4: Average System Cost

1. **Contract System Load:** New Large Single Load (NLSL)

2. *PGE Comment*. PGE's July 23, 2008 comment stated that the New Large Single Load for 2006 was 22,950 MWhs.

3. *BPA Response*. PGE did not supply any documentation to support a reduction in the 2006 NLSL. BPA will continue to assume the NLSL value used in its PGE Draft ASC Report.

4. **Contract System Cost:** New Large Single Load (NLSL) Costs

5. BPA revised the cost of resources used to serve NLSLs to reflect transmission losses between the resource and delivery to the NLSL. All NLSLs are assumed to be served at transmission voltage and transmission losses include the transmission network losses for PGE, in addition to losses of other networks that power from resources travel over to get to the PGE network.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – No Changes

SUPPORTING DOCUMENTATION: Salaries and Wages – No Changes

SUPPORTING DOCUMENTATION: Labor Ratios – No Changes

<u>Miscellaneous Comments</u>

PGE Comment. PGE's July 23, 2008 comment letter also suggested two minor corrections which BPA adopted.

PGE Comment. PGE's July 23, 2008 comment letter suggested that PGE's ASC Forecast Model did not accurately reflect the utility's value of production, transmission and general plant after 2010 and suggests that BPA apply the five-year average growth rate for production, transmission and general plant for the period 2002-2006 to the 2010-2013 period in the ASC Forecast Model.

BPA Response. PGE's issue is valid and BPA recognizes that some growth factor may by appropriate to apply in the ASC Forecast model. PGE's suggestion to use a five-year historical growth rate is but one of many possible methods to use to adjust projected production, transmission and general plant for replacements. BPA will defer consideration of this issue to its next Wholesale Power Rate Case when BPA and other parties will have the opportunity to analyze this issue in greater detail.

B. <u>Identification and Analysis of Issues from Comments to the July 8, 2008 ASC Draft Report</u>

SCHEDULE 1: Plant Investment/Rate Base:

1. **Account 302,** Intangible Plant Franchises and Consents: insufficient support and documentation for Direct Analysis

    a. <u>Statement of Issue</u>: In the May 7 filing, PGE directly assigned this account to Production.

    b. <u>Statement of Facts</u>: The 2008 ASCM permits Direct Analysis only for specified accounts. When utilities perform a Direct Analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. PGE's initial ASC filing did not contain enough information to determine if the functionalization of this Account to Production was reasonable. BPA raised this as an issue in its May 19, 2008 Issue List noting that Direct Analysis of an Account requires detailed documentation and support. In PGE's June 6, 2006 response to BPA's Issue List, additional documentation was provided that supports the functionalization of this Account to Production. PGE's documentation showed that all of the costs in this Account are related either to DEQ Permit costs for Coyote Springs power plant and hydro reliscensing costs.

c. Analysis of Position and Decision: BPA accepts PGE's functionalization of Account 302, Intangible Plant Franchises and Consents.

2. **Account 303,** Intangible Plant Miscellaneous: insufficient support and documentation for Direct Analysis

a. Statement of Issue: In the May 7 filing, PGE directly assigned this Account.

b. Statement of Facts: The 2008 ASCM permits Direct Analysis only for specified accounts. PGE's initial ASC filing did not contain enough information to determine if the functionalization of this Account to was reasonable. BPA raised this as an issue in its May 19, 2008 Issue List noting that Direct Analysis of any an Account requires detailed documentation and support. In PGE's June 6, 2006 response to BPA's Issue List, additional documentation was provided that supports the functionalization of this Account. The documentation contained a detailed breakdown of the software costs by function and the allocation of the costs to Production, Transmission and Distribution/Other. The information was prepared using the OPUC unbundling methodology required under Oregon Senate Bill 1149. BPA agrees with PGE's functionalization. All of the costs contained in this Account are related to computer software.

c. Analysis of Position and Decision: BPA accepts PGE's functionalization of Account 303, Intangible Plant Miscellaneous.

3. **Account 182.3,** Other Regulatory Assets: functionalization of Price Risk and Derivative Assets.

a. Statement of Issue: In the May 7 filing, PGE functionalized Price Risk and Derivative Assets included in Account 182.3 directly to production.

b. Statement of Facts: The 2008 ASCM functionalizes Accounts 175, 176, 244 and 245, derivative assets and liabilities to distribution other. PGE's initial ASC functionalized derivative related costs that were included in Account 182.3, Regulatory Assets to Production. BPA raised this as an issue in its May 19, 2008 Issue List noting that Derivative related costs are functionalized to Distribution/Other. In PGE's June 6, 2006 response to BPA's Issue List, PGE noted that it has argued that these accounts are production-related and has no further comments.

c. Analysis of Position and Decision: The 2008 requires that Accounts 175, 176, 244 and 245, derivative assets and liabilities be functionalized to Distribution/Other. The fact that PGE records some derivative related costs as Regulatory Assets does not allow PGE to functionalize these costs to Production. All derivative related costs are to be functionalized to Distribution/Other, irrespective of what Account they are recorded in. BPA disagrees with PGE on this issue and will functionalize the derivative and price risk management costs included in Account 182.3 to Distribution/Other.

4. **Account 186,** Miscellaneous Deferred Debits.

a. Statement of Issue: In the May 7 filing, PGE functionalized electricity option premium paid cost included in Account 186 directly to Production.

b. Statement of Facts: The 2008 ASCM functionalizes Accounts 175, 176, 244 and 245, derivative assets and liabilities to distribution other. PGE's initial ASC filing functionalized derivative related costs that were included in Account 186, Miscellaneous Deferred Debits to Production. BPA raised this as an issue in its May 19, 2008 Issue List noting that Derivative related costs are functionalized to Distribution/Other. In PGE's June 6, 2006 response to BPA's Issue List, PGE did not respond to this issue.

c. Analysis of Position and Decision: The 2008 requires that Accounts 175, 176, 244 and 245, derivative assets and liabilities be functionalized to Distribution/Other. The fact that PGE records some derivative related costs as Miscellaneous Deferred Debits does not allow PGE to functionalize these costs to Production. All derivative related costs are to be functionalized to Distribution/Other, irrespective of what Account they are recorded in. BPA disagrees with PGE on this issue and will functionalize the derivative and price risk management costs included in Account 186 to Distribution/Other.

5. **Account 253,** Other Deferred Credits.

a. Statement of Issue: In the May 7 filing, PGE functionalized deferred premiums on power options sold included in Account 253 directly to Production.

b. Statement of Facts: The 2008 ASCM functionalizes Accounts 175, 176, 244 and 245, derivative assets and liabilities to distribution other. PGE's initial ASC filing functionalized derivative related costs that were included in Account 253, Other Deferred Credits to Production. BPA raised this as an issue in its May 19, 2008 Issue List noting that Derivative related costs are functionalized to Distribution/Other. In PGE's June 6, 2006 response to BPA's Issue List, PGE did not respond to this issue.

c. Analysis of Position and Decision: The 2008 requires that Accounts 175, 176, 244 and 245, derivative assets and liabilities be functionalized to Distribution/Other. The fact that PGE records some derivative related costs as Other Deferred Credits does not allow PGE to functionalize these costs to Production. All derivative related costs are to be functionalized to Distribution/Other, irrespective of what Account they are recorded in. BPA disagrees with PGE on this issue and will functionalize the derivative and price risk management costs included in Account 253 to Distribution/Other.

SCHEDULE 1A: Cash Working Capital – Changed due to changes from in Schedule 3

SCHEDULE 2: Capital Structure and Rate of Return:

1. **Weighted Cost of Capital:** Weighted Cost of Capital from most recent commission rate order.

a. Statement of Issue: In the May 7 filing, PGE included the Weighted Cost of Capital from its Oregon PUC Rate filing that is currently under review by the Oregon Public Utility Commission.

b. Statement of Facts: BPA's 2008 ASCM allows utility's a return on equity in ASC starting from a Utility's most recent Regulatory Body-approved return. The utility includes the Weighted Cost of Capital from its most recently approved rate order on Schedule 2, which is then grossed up for Federal Income Taxes at the marginal tax rate. In the May 7th filing, PGE included the Weighted Cost of Capital from its Oregon PUC Rate filing that is currently under review by the Oregon Public Utility Commission. When notified of this in the ASC Expedited Review process, PGE submitted a corrected ASC filing, including the Weighted Cost of Capital from its most recently approved rate order.

c. Analysis of Position and Decision: BPA accepted PGE's revised changes to its Weighted Cost of Capital.

SCHEDULE 3: Expenses:

1. **REP Reversal:** PGE included the financial portion of the REP Reversal on Schedule 3 of its Initial ASC Filing.

   a. Statement of Issue: In the May 7 filing, PGE included the financial portion of the REP Reversal on Schedule 3.

   b. Statement of Facts: In the May 7 filing, PGE included the financial portion of the REP Reversal on Schedule 3. BPA raised this as an issue in its May 19, 2008 Issue List noting that the costs included in the REP Reversal should not include the financial portion of this transaction. In PGE's June 6, 2006 response to BPA's Issue List, agreed with BPA.

   c. Analysis of Position and Decision: BPA will remove the financial portion of the REP Reversal from the amount included on Schedule 3. Because the purchased power contract between BPA and PGE associated with the REP Reversal expired in September of 2006, BPA will remove the REP Reversal and the associated entry included in Account 555, Purchased Power for the BPA/PGE contract in the 2009 ASC Forecast Model.

SCHEDULE 3A: Taxes:

1. **Account 408.1** Federal Employment Taxes**:** Support for amounts included in Account 408.1.

   a. Statement of Issue: In the May 7 filing, PGE did not included an explanation of the amounts included in Account 408.1 Federal Employment Taxes

   b. Statement of Facts: In the May 7 filing, PGE did not included an explanation of the amounts included in Account 408.1 Federal Employment Taxes. BPA raised this as an issue in its May 19, 2008 Issue List asking for an explanation of amounts included in Account 408.1. In PGE's June 6, 2006 response to BPA's Issue List, PGE provided an explanation.

   c. Analysis of Position and Decision: BPA accepts PGE's explanation of the amounts included in Account 408.1.

SCHEDULE 3B: Other Included Items:

1. **Account 456** Other Electric Revenues**:** Support for direct analysis of this account.

   a. Statement of Issue: BPA's 2008 ASCM requires that Account 456 Other Electric Revenues be functionalized using Direct Analysis with a default Functionalization to Production. In the May 7^{th} filing, PGE did not perform a Direct Analysis and used the default functionalization to Production.

   b. Statement of Facts: BPA's 2008 ASCM requires that Account 456 Other Electric Revenues be functionalized using Direct Analysis with a default Functionalization to Production. In its May 7^{th} filing, PGE chose the default functionalization to Production for Account 456. BPA raised this as an issue in its May 19, 2008 Issue List asking for an explanation of amounts included in Account 456. In PGE's June 6, 2006 response to BPA's Issue List, PGE stated that it did not have time to perform a Direct Analysis on Account 456 and used the default functionalization to Production, but reserved the right to Perform a Direct Analysis in its October 2008 ASC filing on Account 456.

   c. Analysis of Position and Decision: BPA accepts PGE's functionalization of Account 456.

SCHEDULE 4: Average System Cost

1. **Distribution Losses**:

   a. Statement of Issue: In its filing, PGE used a 5% Distribution Loss Factor in determination of its ASC.

   b. Statement of Facts: The May 7th filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years.

   Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

c. Analysis of Position and Decision: For purposes of the expedited filing, BPA completed the Distribution Loss Factor calculation outlined in the ASCM ROD, Section 4.10.5.

2. **Contract System Load:** New Large Single Load (NLSL)

a. Statement of Issue: PGE submitted data identifying two potential NLSLs with usage of 328,992 MWh.

b. Statement of Facts: PGE submitted data identifying two potential NLSLs with usage of 328,992 MWh. BPA reviewed data on the NLSL supplied by PGE.

c. Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit costs of servicing an NLSL to be included in the calculation of a Utility's ASC and BPA agrees with PGE's removal of the 2 potential NLSLs from Contract System Load.

3. **Contract System Cost:** New Large Single Load (NLSL) Costs

a. Statement of Issue: The May 7 filing Appendix 1 template includes an estimate of the costs of resources used to serve the 2 potential NLSLs.

b. Statement of Facts: PGE's estimate of the costs of resources used to serve the 2 potential NLSLs was prepared before BPA published the 2008 ASCM. BPA determined the cost of serving the potential NLSL using the fully allocated cost of all escalated base period post-September 1, 1979, resources and major resource additions and long-term power purchases (5 years or longer contracts) used to determine Exchange Period ASCs as outlined in the ASCM ROD, section 4.5.

c. Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit costs of serving an NLSL to be included in the calculations of a Utility's ASC. BPA revised the costs of resources used to serve the 2 potential NLSLs in the Appendix 1 amended filing. The results are noted in Schedule 4 of the amended Appendix 1 filing and in Table 2 at the end of this report. In addition, BPA will publish its calculation of resource costs used to serve NLSLs for PGE and other utilities at the ASCM web site: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale –

1. **Account 555** Purchased Power: PGE's RL contract with BPA.

   a. Statement of Issue: PGE's 2006 FERC Form 1 includes the costs and MWH associated with a purchase contract that expired in September of 2006.

   b. Statement of Facts: BPA's ASC template did not include revenue associated with the Fale-Safe Corporation Purchase on Page 327.2, Line 8 and several miscellaneous adjustments included on Page 327.7.

   c. Analysis of Position and Decision: For purposes of the expedited filing, BPA corrected PGE's ASC filing to include the items missed by the ASC template. It will review the ASC template to ensure that such items are not omitted in the future.

SUPPORTING DOCUMENTATION: Salaries and Wages – No Changes

SUPPORTING DOCUMENTATION: Labor Ratios

1. **Maintenance of General Plant (GPM) Ratio:** Miscellaneous Equipment

   a. Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

   b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

   c. Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

C. Identification and Analysis of Issues from Comments to the August 4, 2008 Revised Draft ASC Report

SCHEDULE 1: Plant Investment/Rate Base–

1. For Account 108, line item "**Capital Leases - Common Plant"** and **In-Service: Depreciation of Common Plant**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

   b. Analysis of Position and Decision: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments** (**Electric)**, Account 114, line 92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4, 2008 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4, 2008 report

SCHEDULE 3: Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)**

a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/Rate Base*** **(Acquisition Adjustments (Electric)**, (cell E92 in electronic template).

b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses:

b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4, 2008 report

SCHEDULE 3B: Other Included – no changes from the August 4, 2008 report

SCHEDULE 4: Average System Cost - – no changes from the August 4, 2008 report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

a. Statement of Issue: For Labor Ratio Input: line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

b. Analysis of Position and Decision: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908: all exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

D. August 4, 2008 - Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC are allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that Utility's retail load during the BPA rate period. The change in ASC must meet the materiality threshold as the change in ASC resulting from adding major new resources, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more.

PGE submitted the following information on new resources with their ASC filing. The first column shows the effect of removing the RL purchase from BPA. The model will replace the MWhs purchased at the RL rate with market purchases.

Table 1: ASC New Resource Additions

		Online Year	2007	2007	2007	2009	2009
		Online Month	1	6	12	4	4
			01/01/07	06/01/07	12/01/07	04/01/09	04/01/09
Other Production Plant							
Other Production	340-346			250,408,852	226,295,378	80,500,000	345,000,000
Fuel Stock	151						
Plant Materials and Operating Supplies	154			89,568			
EPA Allowances	158.1-158.2						
Other Expense							
Other Power - Fuel	547			90,340,172	3,244,333		2,296,333
Other Power - Operations (Excluding 547 - Fuel)	546-550			1,849,114	1,157,000		
Other Power - Maintenance	551-554			4,323,592	3,727,000		
Property Insurance	924			145,000	530,000	188,537	808,015
Depreciation	403	OK		4,582,000	11,718,000	1,610,000	17,864,748
Firm Sales for Resale ($)	447	OSS & PP					
Firm Sales for Resale (MWh)		OSS & PP					
Expected Annual Generation (MWh)		OSS & PP		2,033,378	417,515	0	501,018
Property Taxes Production							
Total Production Property	262			2,437,809	2,094,000	1,208,912	5,181,051
Purchased Power Contracts (From BPA)							
PF Purchase Cost ($)							
PF Purchased Power (MWh)							
Slice Purchase Cost ($)							
Slice Purchased Power (MWh)							
PF Generic #1 Purchase ($)							
PF Generic #1 Purchasd Power (MWh)							
PF Generic #2 Purchase ($)							
PF Generic #2 Purchasd Power (MWh)							
Contract Termination ($)							
Contract Termination (MWh)							
Purchased Power Contracts (Market)							
Contract Termination ($)		OSS & PP	(43,681,235)				
Contract Termination (MWh)		OSS & PP	(1,690,158)				
Purchased Power (Excluding REP Reversal)	555	OSS & PP					
Purchased Power (MWh)		OSS & PP					
System Control and Load Dispatching	556						
Other Expenses	557						
Transmission Plant							
Transmission Plant	350-359			23,632,333			
Plant Materials and Operating Supplies							
Transmission Expenses							
Transmission of Electricity to Others (Wheeling)	565						
Total Operations less Wheeling	560-567						
Total Maintenance	568-573						
Property Insurance	924						
Depreciation	403			491,580			
Other Electric Revenues	456						
Revenues from Transmission of Electricity of Others (i)	456.1						
Property Taxes Transmission							
Total Transmission Property	262						

E. July 8, 2008 - Exchange Period ASC New Resource Additions

Table 1 Revised: ASC New Resource Additions

			Online Year	2007	2007	2009	2009	2007
			Online Month	6	12	4	4	1
				06/01/07	12/01/07	04/01/09	04/01/09	01/01/07
Other Production Plant								
Other Production	340-346			250,408,852	226,295,378	80,500,000	345,000,000	
Fuel Stock	151							
Plant Materials and Operating Supplies	154			89,568				
EPA Allowances	158.1-158.2							
Other Expense								
Other Power - Fuel	547			90,340,172	3,244,333		2,296,333	
Other Power - Operations (Excluding 547 - Fuel)	546-550			1,849,114	1,157,000			
Other Power - Maintenance	551-554			4,323,592	3,727,000			
Property Insurance	924			145,000	530,000	188,537	808,015	
Depreciation	403	OK		4,582,000	11,718,000	1,610,000	17,864,748	
Firm Sales for Resale ($)	447	OSS & PP						
Firm Sales for Resale (MWh)		OSS & PP						
Expected Annual Generation (MWh)		OSS & PP		2,033,378	417,515	0	501,018	
Property Taxes Production								
Total Production Property	262			2,437,809	2,094,000	1,208,912	5,181,051	
Purchased Power Contracts (From BPA)								
PF Purchase Cost ($)								
PF Purchased Power (MWh)								
Slice Purchase Cost ($)								
Slice Purchased Power (MWh)								
PF Generic #1 Purchase ($)								
PF Generic #1 Purchasd Power (MWh)								
PF Generic #2 Purchase ($)								
PF Generic #2 Purchasd Power (MWh)								
PF Generic #3 Purchase ($)								
PF Generic #3 Purchasd Power (MWh)								
Purchased Power Contracts (Market)								
Purchased Power (Excluding REP Reversal)	555	OSS & PP						(118,730,120)
Purchased Power (MWh)		OSS & PP						(1,690,158)
System Control and Load Dispatching	556							
Other Expenses	557							
Transmission Plant								
Transmission Plant	350-359			23,632,333				
Plant Materials and Operating Supplies								
Transmission Expenses								
Transmission of Electricity to Others (Wheeling)	565							
Total Operations less Wheeling	560-567							
Total Maintenance	568-573							
Property Insurance	924							
Depreciation	403			491,580				
Other Electric Revenues	456							
Revenues from Transmission of Electricity of Others (i)	456.1							
Property Taxes Transmission								
Total Transmission Property	262							

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining PGE's forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and PGE's ASCs published in the July 8, 2008 report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and PGE's ASCs as appropriate and as a result of PGE's comments to the July 8, 2008 report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and PGE's ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: Draft FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	$983,882,624	$986,083,703	$997,133,635	$1,018,504,435	$1,042,287,576
Transmission	114,158,885	114,630,209	115,352,492	116,117,639	116,958,740
NLSL Resource Cost ($/MWh)	70.98	69.33	67.47	66.69	65.89
(Less) NLSL Costs	23,352,660	22,810,279	22,197,059	21,940,281	21,678,532
Contract System Cost	**$1,074,688,849**	**$1,077,903,633**	**$1,090,289,068**	**$1,112,681,794**	**$1,137,567,783**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	18,238,510	18,639,757	19,049,832	19,468,928	19,897,245
(Less) NLSL	328,992	328,992	328,992	328,992	328,992
Total Retail Load (Net or NLSL)	17,909,518	18,310,765	18,720,840	19,139,936	19,568,253
Distribution Loss	859,034	877,933	897,247	916,987	937,160
Contract System Load	**18,768,552**	**19,188,698**	**19,618,087**	**20,056,923**	**20,505,413**

AVERAGE SYSTEM COST

ASC ($/MWh)	**$57.26**	**$56.17**	**$55.58**	**$55.48**	**$55.48**

Table 2: Revised FY 2009-2013 ASC Summary – August 4, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	$986,346,826	$979,019,415	$1,010,360,845	$1,033,551,441	$1,060,622,115
Transmission	114,158,885	114,630,209	115,352,492	116,117,639	116,958,740
NLSL Fully Allocated Cost ($/MWh)	73.33	69.43	69.48	68.77	67.96
(Less) NLSL Costs	24,124,218	22,842,949	22,859,327	22,623,455	22,359,524
Contract System Cost	**$1,076,381,493**	**$1,070,806,676**	**$1,102,854,011**	**$1,127,045,625**	**$1,155,221,331**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	18,238,510	18,639,757	19,049,832	19,468,928	19,897,245
(Less) NLSL	328,992	328,992	328,992	328,992	328,992
Total Retail Load (Net of NLSL)	17,909,518	18,310,765	18,720,840	19,139,936	19,568,253
Distribution Loss	859,034	877,933	897,247	916,987	937,160
Contract System Load	**18,768,552**	**19,188,698**	**19,618,087**	**20,056,923**	**20,505,413**

AVERAGE SYSTEM COST

ASC ($/MWh)	**$57.35**	**$55.80**	**$56.22**	**$56.19**	**$56.34**

Table 2: Final FY 2009-2013 ASC Summary – September 11, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	$989,569,836	$982,643,846	$1,014,355,729	$1,037,931,055	$1,065,378,501
Transmission	114,363,956	114,881,485	115,645,517	116,453,938	117,336,870
NLSL Resource Cost ($/MWh)	73.34	69.45	69.50	68.78	67.98
(Less) NLSL Costs	24,127,751	22,847,185	22,864,160	22,628,883	22,365,495
Contract System Cost	**$1,079,806,041**	**$1,074,678,147**	**$1,107,137,086**	**$1,131,756,110**	**$1,160,349,876**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	18,238,510	18,639,757	19,049,832	19,468,928	19,897,245
(Less) NLSL	328,992	328,992	328,992	328,992	328,992
Total Retail Load (Net of NLSL)	17,909,518	18,310,765	18,720,840	19,139,936	19,568,253
Distribution Losses	859,034	877,933	897,247	916,987	937,160
Contract System Load	**18,768,552**	**19,188,698**	**19,618,087**	**20,056,923**	**20,505,413**

AVERAGE SYSTEM COST

ASC ($/MWh)	**$57.53**	**$56.01**	**$56.43**	**$56.43**	**$56.59**

VI. BPA STATEMENT

This ASC determination is BPA's best estimate of PGE's FY 2009 ASC based on the information and data provided from PGE during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination, FY 2009. This determination is made solely for purposes of providing estimated FY 2009 ASCs for use in the development of BPA's FY 2009 power rates in BPA's WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such review will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance to the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System Cost of PGE for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The Final Appendix 1 Filing, Forecast Model, and NLSL assessment used to calculate PGE's ASCs can be viewed at BPA ASC website:

http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

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FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

Puget Sound Energy

Docket Number: PS-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

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TABLE OF CONTENTS

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I. FILING DATA

Utility	Parties to the Filing
Puget Sound Energy P.O. Box 97034 Bellevue, WA 98009-9734	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
Production Cost	$1,218,999,283	$1,202,482,570	$1,202,482,570	$ 1,203,829,932
Transmission Cost	$ 86.098,233	$86,233,879	$86,233,879	$85,928,863
(Less) New Large Single Load Costs				
Total Contract System Cost	$1,305,097,516	1,288,716,449	1,288,716,449	$1,289,758,795
Total Retail Load (MWh)	21,099,045	21,099,045	21,099,045	21,099,045
(Less) New Large Single Load				0
Total Retail Load (Net NLSL)	21,099,045	21,099,045	21,099,045	21,099,045
Plus Distribution Losses	966,336	1,052,842	1,052,842	1,052,842
Total Contract System Load (MWh)	22,065,381	22,151,887	22,151,887	22,151,887
FY 2006 Base Period ASC ($/MWh)	**$59.15**	**$58.18**	**$58.18**	**$58.22**

B. FY 09 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept. 11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**$62.67**	**$58.26**	**$59.71**

C. FY 09 (Exchange Period) ASC with New Resource Additions ($/MWh)

FY 2007-2009 New Resource Additions: N/A
There are no New Resource Additions recorded.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. See 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging Utilities agreed to a number of termination agreements that provided for payments to each Utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the REP, including the development of RPSAs and a consultation proceeding to revise the 1984

ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing Utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

For more information regarding the proposed 2008 ASCM, refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. <u>ASC Determination Process Guidelines and Expedited Review Process</u>

The purpose of BPA's expedited review process is to estimate exchanging Utilities' ASCs for FY 2009 that could be noticed by the Administrator and incorporated into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding rely on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance to the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1.

The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a base period ASC determination, BPA used the ASC Forecast model, an excel based spreadsheet, to escalate the base year ASC forward to the effective rate period, FY 2009 (October 1, 2008 thru September 30, 2009). The base year and forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capitol (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1 to determine the Utility's return on investment.

IOUs use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For COUs, the rate of return is equal to the COU's weighted cost of debt.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as described above. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items. The schedule also lists the load information, as defined below, and calculates the Utility's ASC.

Contract System Cost:
The Contract System Cost is the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Load:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any New Large Single Load(s) (NLSL).

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Sales for Resale

The Purchased Power is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1, pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A new large single load (NLSL) is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro rata basis using salary and wage data for production, transmission, and distribution/other functions included in the Utility's most recently filed Form 1. For consumer-owned utilities, comparable data is used based on the cost of service study used as the basis for retail rates at the time of review.

D. <u>ASC Forecast</u>

The Base Period ASC is applied to an Excel-based forecasting model to escalate the Base Year ASC data forward to the Exchange Period. For purposes of the expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Costs

Forecast Contract System Costs (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5%. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of any major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of the major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. Identification and Analysis of Issues from the May 7, 2008 ASC Appendix 1 Filing

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Costs and codes filed on May 7, 2008 by Puget Sound Energy (PSE), and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base

1. **302 Franchise & Consent; Snoqualmie Project #2493 License**

   a. Statement of Issue: In the May 7 filing, Puget Sound Energy (PSE) directly assigned this account to Production, without supply adequate support for the Direct Analysis.

   b. Statement of Facts: Account 302 Franchise and Consent sub accounts are to be functionalized using Direct Analysis with a default functionalization using the PTD ratio.

c. Puget Sound Energy's Response to the Issue: PSE's Snoqualmie Falls hydroelectric generating station is located on the Snoqualmie River, in Snoqualmie, Washington. The Snoqualmie Project consists of a diversion dam located 150 feet upstream from Snoqualmie Falls, and two powerhouses (Plants 1 and 2) with a total installed capacity of 44.4 MW. Snoqualmie Plant 1 was originally constructed in 1898 and contains the world's first completely underground powerhouse, built in a cavity 270 feet below Snoqualmie Falls. Snoqualmie Plant 2, about ¼ a mile downstream from Plant 1, was built in 1910 and expanded in 1957. The original license for the Snoqualmie Project was issued on May 13, 1975, effective as of March 1, 1956. That license expired on December 31, 1993. PSE filed the Snoqualmie Project license application with FERC on November 25, 1991. FERC issued the new 40-year license on June 29, 2004. Snoqualmie Project #2493 License costs are amortized over the life of the new license which is 40 years.

d. Analysis of Position and Decision: Puget Sound Energy has provided sufficient information to support the functionalization of Account 302 Franchise and Consent Snoqualmie Project #2493 License to Production.

2. **Account 302 Franchise & Consent; Other**

a. Statement of Issue: In the May 7 filing, Puget Sound Energy directly functionalized this account without showing the basis of the direct assignments.

b. Statement of Facts: Account 302 Franchise and Consent sub accounts are to be functionalized using Direct Analysis with a default functionalization using the PTD ratio.

c. Puget Sound Energy's Response to the Issue: For purposes of PSE's ASC Methodology Expedited Process and Consultation ASC template, electric franchise and license costs other than production facility licensing costs in this account are currently functionalized in the direct analysis using the PTD ratio. This functionalization may be updated if and when additional data about these assets becomes available, or PSE may use the CORPORATE ratio as a proxy for the cross functional nature of these assets.

d. Analysis of Position and Decision: Puget Sound Energy used the PTD ratio to functionalizes Account 302 Franchise & Consent; Other. In the October 1, 2008 filing Puget Sound Energy will be required to show that the data within Account 302 Franchise & Consent; Other should be functionalized with the PTD ratio.

3. **Account 303 Intangible Miscellaneous– Rock Island**

a. Statement of Issue: In the May 7 filing, Puget Sound Energy directly functionalized this account to Production without showing the basis of the direct assignments.

b. Statement of Facts: Account 303 Intangible Miscellaneous sub accounts are to be functionalized using Direct Analysis with a default functionalization of Distribution/Other.

c. Puget Sound Energy's Response to the Issue: The Rock Island Expansion costs in this account relate to expansion of the Rock Island Dam hydroelectric generating station. PSE shares in the cost of this production asset.

d. Analysis of Position and Decision: Puget Sound Energy has provided sufficient information to support the functionalization of Account 303 Intangible Miscellaneous: Rock Island to Production.

4. **Account 303 Intangible Miscellaneous– Other**

a. Statement of Issue: In the May 7 filing, Puget Sound Energy directly functionalized this account without showing the basis of the direct assignments.

b. Statement of Facts: Account 303 Intangible Miscellaneous: Other sub accounts are to be functionalized using Direct Analysis with a default functionalization of Direct Distribution.

c. Puget Sound Energy's Response to the Issue: For purposes of PSE's ASC Methodology Expedited Process and Consultation ASC template, these other costs in this account will be functionalized across production, transmission and distribution using the CORPORATE ratio direct analysis. The CORPORATE ratio reflects the cross functional utilization of these technology assets.

d. Analysis of Position and Decision: Puget Sound Energy used a "Corporate Ratio" to functionalize Account 303 Intangible Miscellaneous: Other. This account is to be functionalized with either Direct Analysis or directly to Distribution. The "Other" sub accounts of Account 303 represent approximately 91% of Account 303 Intangible Miscellaneous: Other. Direct Analysis requires the utility to provide the listing of the items in this account as well as adequate support for the functionalization. In the October 1, 2008 ASC filing Puget Sound Energy will be required to functionalize this account using Direct Analysis, direct analysis of any functionalization ratio used or with the Default to Distribution.

5. **Account 182.3 Other Regulatory Assets - Def AFUDC - Regulatory Asset**

a. Statement of Issue: In its May 7 filing, Puget Sound Energy functionalized Account 182.3 Other Regulatory Assets - Def AFUDC - Regulatory Asset to Production, Transmission and Distribution using the PTD ratio.

b. Statement of Facts: Account 182.3 Other Regulatory Assets is to functionalize using Direct Analysis, with the default functionalization being Direct Distribution. AFUDC is a component of CWIP. CWIP is functionalized to Distribution.

c. Puget Sound Energy's Response to the Issue: This regulatory asset – No. 18230031 018230031 Electric - Def AFUDC - Regulatory Asset – relates to the excess of WUTC allowed AFUDC over the amount allowed by FERC through the FERC formula. The balance in this account is amortized monthly to order 40600021 Electric WUTC AFUDC amortization, per docket U-82-38. This regulatory asset is part of the jurisdictional rate base calculation. Authorization of Regulatory Treatment is included in Washington Commission order UE-060266 and UG-060267. For purposes of the ASC Methodology Expedited Process and Consultation ASC template, the DIRECT analysis of this regulatory asset resulted in it being functionalized to PTD to reflect the cross functional characteristics of CWIP which can be production, transmission, or distribution-related construction. This functionalization may be updated if and when additional data about the underlying construction projects becomes available.

d. Analysis of Position and Decision: Puget Sound Energy shows that this account is part of their rate proceedings. However AFUDC is closed to CWIP. CWIP is not an exchangeable cost. BPA has functionalized Account 182.3 Other Regulatory Assets - Def AFUDC - Regulatory Asset to Distribution.

6. **Account 182.3 Other Regulatory Assets - FAS 109 Taxes**

a. Statement of Issue: In its May 7 filing, Puget Sound Energy functionalized Account 182.3 Other Regulatory Assets – FAS 109 Taxes using the PTD ratio.

b. Statement of Facts: Federal Income taxes are calculated using the Marginal Tax Calculation. All other Federal Taxes, (Assets/Liabilities) are to be functionalized to Distribution.

c. Puget Sound Energy's Response to the Issue: For purposes of the ASC Methodology Expedited Process and Consultation ASC template, PSE revises the functionalization of this asset to other.

d. Analysis of Position and Decision: Puget Sound Energy agrees with BPAs position and Account 182.3 Other Regulatory Assets – FAS 109 Taxes will be functionalized to Distribution.

7. **Account 182.3 Other Regulatory Assets - Tenaska Regulatory Asset**

a. Statement of Issue: In its May 7 filing, Puget Sound Energy functionalized Account 182.3 Other Regulatory Assets – Tenaska Regulatory Asset to Production without sufficient information to support the Direct Analysis.

b. Statement of Facts: Account 182.3 Other Regulatory Assets is to be functionalize using Direct Analysis, with the default functionalization being Direct Distribution,

c. Puget Sound Energy's Response to the Issue: PSEs regulatory asset No. 018230001 Tenaska Regulatory Asset relates to PSE's gas contract for the Tenaska cogeneration facility. This account includes the buyout cost and capitalized interest related to purchasing supply contracts on PURPA facilities. The deferred balance of each activity will be amortized over the life of the contract, per docket UE-971619. This asset is part of the jurisdictional rate base calculation. The regulatory treatment of the Tenaska Regulatory Asset is described in WUTC Docket No. UE-031725 at paragraph 95. Per paragraph 95(1), PSE will recover fully its Tenaska-related costs if net Tenaska costs fall at or below the benchmark. Paragraph 95(2) describes the consequences on return of the asset if the benchmarks are not met. The paragraph goes on to say that PSE will recover fully the actual costs of gas and return of the regulatory asset even if the benchmark is exceeded.

d. Analysis of Position and Decision: Puget Sound Energy has provided adequate support for the Direct Analysis of Account 182.3 Other Regulatory Assets – Tenaska Regulatory Asset to Production.

8. **Account 182.3 Other Regulatory Assets – 2001 & 2004 Rate Case Electric**

a. Statement of Issue: In its May 7 filing, Puget Sound Energy functionalized Account 182.3 Other Regulatory Assets – 2001 & 2004 Rate Case Electric Asset using the CORPORATE DIRECT analysis ratio.

b. Statement of Facts Account 182.3 Other Regulatory Assets is to functionalize using Direct Analysis, with the default functionalization being Direct Distribution. The cost of Rate Cases either as a deferred asset or a direct cost (Account 928 Regulatory Commission Expenses) is to be functionalized to Distribution.

c. Puget Sound Energy's Response to the Issue: This asset relates to a General Rate case with the WUTC. General rate cases with the WUTC address the production, transmission and distribution functions of utility service. For purposes of PSE's ASC Methodology Expedited Process and Consultation ASC template, these general rate case related regulatory assets and associated amortization expense is functionalized using the CORPORATE DIRECT analysis ratio to reflect the cross-functional nature of the topics addressed in general rate case proceeding.

d. Analysis of Position and Decision: Puget Sound Energy shows that this account represents a cost of business, however costs associated with rate cases or regulatory proceedings is to be functionalized to Distribution. BPA has functionalized Account 182.3 Other Regulatory Assets - Def AFUDC - Regulatory Asset to Distribution.

9. **Account 182.3 Other Regulatory Assets - Hopkins Ridge BPA Transmission Upgrades**

a. Statement of Issue: In its May 7 filing, Puget Sound Energy functionalized Account 182.3 Other Regulatory Assets – Hopkins Ridge BPA Transmission Upgrades to Production.

b. Statement of Facts: Account 182.3 Other Regulatory Assets is to be functionalized using Direct Analysis, with the default functionalization being Direct Distribution.

c. Puget Sound Energy's Response to the Issue: PSE had intended to functionalize this Hopkins Ridge BPA Transmission Upgrades asset to Transmission in the ASC Methodology Expedited Process and Consultation ASC template.

d. Analysis of Position and Decision: Puget Sound Energy agrees that Account 182.3 Other Regulatory Assets – Hopkins Ridge BPA Transmission Upgrades should be functionalized to Transmission. BPA has functionalized Account 182.3 Other Regulatory Assets – Hopkins Ridge BPA Transmission Upgrades to Transmission.

10. **Account 182.3 Other Regulatory Assets - Electric - BPA Power Exch Invstmt - Reg Asset**

a. Statement of Issue: In its May 7 filing, Puget Sound Energy functionalized Account 182.3 Other Regulatory Assets - Electric - BPA Power Exch Invstmt - Reg Asset to Production.

b. Statement of Facts: Account 182.3 Other Regulatory Assets is to be functionalized using Direct Analysis, with the default functionalization being Direct Distribution.

c. Puget Sound Energy's Response to the Issue: Line 4 of page 232 Other Regulatory Assets in the FERC Form 1 is comprised of two offsetting accounts: Regulatory Asset No. 018230071 Electric - BPA Power Exch Invstmt - Reg Asset, and Regulatory Asset No. 018230081 Electric - BPA Power Exch Inv Amort - Reg Asset. This account is used to record the amortization of the BPA Power Exchange Investment recorded in account 18230071, per Cause U-89-2688-T. Both of these accounts are part of the jurisdictional rate base calculation. These accounts are functionalized to production.

d. Analysis of Position and Decision: Puget Sound Energy has provided sufficient information to support the functionalization of Account 182.3 Other Regulatory Assets - Electric - BPA Power Exch Invstmt - Reg Asset to Production.

11. **Account 182.3 Other Regulatory Assets - Chelan County PUD Contract Initiation**

a. Statement of Issue: In its May 7 filing, Puget Sound Energy functionalized Account 182.3 Chelan County PUD Contract Initiation to Production without adequate information to support this functionalization

b. Statement of Facts: Account 182.3 Other Regulatory Assets is to be functionalized using Direct Analysis, with the default functionalization being Direct Distribution.

c. Puget Sound Energy's Response to the Issue: This regulatory asset relates to the Chelan County PUD Contract Initiation fee paid by PSE to Chelan County PUD for a new 20 year contract that will commence after the current 50 year contract expires in 2011. This regulatory asset accrues interest at the net of tax rate of return because the customers that will be receiving the benefit of the power should pay the carrying costs of securing the power. Amortization of this asset will begin once the power under the new contract starts being delivered to PSE. This regulatory asset and its associated amortization, once that commences, should be functionalized to production. .

d. Analysis of Position and Decision: Puget Sound Energy has provided information that shows Account 182.3 Chelan County PUD Contract Initiation is a Regulatory Asset. However, the asset will not be recovered in rates prior to the end current Chelan contract that expires in 2011. Since this account is not part of Puget's rate base for regulatory purposes, Account 182.3 Chelan County PUD Contract Initiation is a Regulatory Asset will be functionalized to Distribution.

SCHEDULE 1A: Cash Working Capital – no changes

SCHEDULE 2: Capital Structure and Rate of Return

1. **Embedded Cost of Debt**

a. Statement of Issue: Did Puget Sound Energy use the Correct Weighted Cost of Debt.

b. Statement of Facts: Puget Sound Energy provided a 6.83% cost of Debt. The weighted cost of debt is calculated to be 3.82%. BPA asked why the cost of debt varied from 6.819%

c. Puget Sound Energy's Response to the Issue: For purposes of PSE's ASC Methodology Expedited Process and Consultation ASC template, PSE's weighted cost of debt is equal to 3.82%. This result is based on an average cost of 6.83% (comprised of the costs of Long-Term Debt, Short-Term Debt and Trust Preferred) and a capitalization ratio of 55.95% per ORDER 08 in WUTC DOCKETS UE-060266 and UG-060267 (consolidated).

d. Analysis of Position and Decision: Puget Sound Energy has provided sufficient information that supports the use of 6.83% cost of Debt.

SCHEDULE 3: Expenses

1. **Account 908 - Customer Assistance Expenses (Major only)**

a. Statement of Issue: The functionalization of Account 908 Customer Assistance Expenses was functionalized using Direct Analysis.

b. Statement of Facts: Functionalization using Direct Analysis for Account 908 Customer Assistance Expenses is required. Direct Analysis must be supported with sufficient details of the account and justification of the functionalization.

c. Puget Sound Energy's Response to the Issue: For ratemaking purposes, conservation is a production resource. All conservation related expenditures (regulatory assets and their associated amortization expense) are therefore functionalized to production in the ASC. Conservation expenditures and the amortization rates used to amortize those expenditures are determined based on applying PSE's production classification and production allocation factors (peak credit method) to conservation expenditures (per the WUTC conservation tracker/rider cost recovery provisions.) Amortization of conservation expenditures using these amortization rates are booked to Account 908 and these costs in account 908 are therefore functionalized to production in the ASC.

d. Analysis of Position and Decision: Puget Sound Energy has provided sufficient information that supports the functionalization of Account 908 Customer Assistance Expenses.

2. **Account 908 - Customer Assistance Expenses: Low Income Program**

a. Statement of Issue: Correct functionalization of Account 908 Customer Assistance Expenses was functionalized using Direct Analysis.

b. Statement of Facts: Functionalization using Direct Analysis for Account 908 Customer Assistance Expenses Low Income Program is required. Direct Analysis must be supported with sufficient details of the account and justification of the functionalization.

c. Puget Sound Energy's Response to the Issue: Several programs (PSE Help Program, Warm Home Fund, and LIHEAP Program) are available to low-income customers of PSE to help reduce natural gas or electricity bills and make homes more weatherproof. This assistance can help customers avoid having to choose between paying their utility bill and paying for other necessities such as food, rent, or medicine. Most of these programs are administered by the Energy Assistance Agencies.

1. PSE's HELP Program provides additional bill-payment assistance (beyond the federal LIHEAP program) to qualified PSE customers.

2. The PSE HELP Program is funded by PSE rate payers through low income tracker/rider rates. Billed low income revenue resulting from these tracker/rider rates is reclassified to a liability by recording the total offsetting expense to a sub account in Account 908.

3. The low income funds are used to pay for the retail utility services provided to the low income customer from the utility's production, transmission and distribution system.

4. The Account 908 Low income liability should be functionalized using a method that reflects the utility-wide nature of the services being funded for the low income customer (i.e., retail utility service). For purposes of PSE's ASC Methodology Expedited Process and Consultation ASC template, the CORPORATE ratio was used. This ratio is a composite of functionalized return on rate base plus functionalized operation and maintenance (O&M) expense net of purchase power. The ratio reflects the plant/asset component of utility service as well as the operation and maintenance expense incurred by PSE to provide retail service.)

d. Analysis of Position and Decision: Puget Sound Energy is correct in functionalizing conservation to Production. Because this account is tied to Account 253 Low Income Program – Electric, a change in functionalization would include changing a liability that was not noted in the BPA Issues List. BPA will address Account 908 Customer Assistance Expenses Low Income Program in the October 1, 2008 ASC filing.

3. **Account 40100011 - Amortization of Account 302 Franchise and License**

a. Statement of Issue: In the May 7, 2008 filing, Puget used Direct Analysis to functionalize Account 40100011 - Amortization of Account 302 Franchise and License

b. Statement of Facts: The amortization of Account 302 Franchise and Consent sub accounts are to be functionalized using Direct Analysis with a default functionalization using the PTD ratio. The direct analysis must have sufficient information to justify the functionalization of the account.

c. Puget Sound Energy's Response to the Issue: The functionalization of amortization of the electric franchise and license intangible assets follows the functionalization of the related asset. For purposes of PSE's ASC Methodology Expedited Process and Consultation ASC template, this expense is currently functionalized using the default functionalization for Accounts 302 and 303, except as indicated on tab DIRECT Int Amort E302 and E303. This functionalization may be updated for purposes of the October 1 template filing to more fully reflect the functional nature of the underlying assets. Additional information/data describing each of the assets associated with this amortization expense will be provided as/if available.

d. Analysis of Position and Decision: Puget Sound Energy is consistent in the functionalization of the Asset account and Amortization account.

4. **Account 4040091 Amortization of Account 302 and 303**

a. Statement of Issue: In the May 7, 2008 filing, Puget used Direct Analysis to functionalize Account 4040091 - Amortization of Account 302 Intangible Plant.

b. Statement of Facts: The amortization of Account 4040091 - Amortization of Account 302 Intangible Plant is to be done with Direct Analysis or with the default functionalization ratios. The direct analysis must have sufficient information to justify the functionalization of the account.

c. Puget Sound Energy's Response to the Issue: The functionalization of amortization of the Electric Computer Software intangible assets follows the functionalization of the related asset. For purposes of PSE's ASC Methodology Expedited Process and Consultation ASC template, this expense is currently functionalized through direct analysis. This direct analysis functionalized the asset and associated amortization expense based on the functional nature of the specific asset included in the account and utilized the direct analysis ratio CORPORATE to functionalize some of the assets included in this account. The functionalization of this account will be updated for purposes of the October 1 template filing to more fully reflect the functional nature of the underlying assets. Additional information/data describing each of the assets associated with this amortization expense will be provided as/if available.

d. Analysis of Position and Decision: Puget Sound Energy is consistent in the functionalization of the Asset account and Amortization account.

5. **Account 4040312 – Amortization of Account E302 and E303 Fredonia #3 & #4**

a. Statement of Issue: In the May 7, 2008 filing, Puget used Direct Analysis to functionalize Account 4040312 - Amortization of Account E302 and E303 Fredonia #3 & #4.

b. Statement of Facts: The amortization of Account 4040091 - Amortization of Account 302 Intangible Plant is to be done with Direct Analysis or with the default functionalization ratios. The direct analysis must have sufficient information to justify the functionalization of the account.

c. Puget Sound Energy's Response to the Issue: Fredonia #3 and #4 are PSE gas turbine generating plants. The amortization schedule for this asset is based on an amortization period of 5 years and 7 months.

d. Analysis of Position and Decision: Puget Sound Energy is correct in the functionalization of this account. In the review of Accounts 302 & 303, Fredonia #3 & #4 is not detailed. In the October 1, 2008 ASC filing the fictionalization of this account will be reviewed.

6. **Account 404 – Amortization of Intangible Assets (302 & 303)**

a. Statement of Issue: In its May 7th filing, Puget Sound Energy functionalized the amortization of 302 Franchise & Consent to Production. In addition, account 303 was functionalized using Direct Analysis. What is the regulatory treatment of this account?

b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production.

c. Puget Sound Energy's Response to the Issue: The amortization of the rate base in these accounts follows the treatment accorded the rate base described above.

d. Analysis of Position and Decision: Puget Sound Energy has provided sufficient information to support the functionalization of Account 302 & 303 –Amortization of Intangible Plant

7. **Account 404 – Direct Common Depr & Amort Exp – Common Plant**

a. Statement of Issue: In its May 7th filing, did Puget Sound Energy include Common Plant associated with the Gas utility in the ASC calculation.

b. Statement of Facts: The ASC for each utility includes only exchangeable Electric costs.

c. Puget Sound Energy's Response to the Issue: The common utility general plant and related expenses associated with the Gas business have been removed from the total common utility general plant and related expense. The common utility expenses in Accounts 901-935 associated with the gas utility are shown on pages 356 and 357 of the FERC Form 1. The electric portion of these accounts are also shown on these pages and are also included in the total electric utility account balances for Accounts 901-935 shown on pages 322-232 of the FERC Form 1. The account balances on pages 322-232 are the inputs for the ASC on tab Sch 3 – Expenses and these balances do not include the gas portion.

d. Analysis of Position and Decision: Puget Sound Energy has provided sufficient information to support the functionalization of Account 404 – Direct Common Depr & Amort Exp – Common Plant

8. **Account 404 – Amortization of Limited Term Electric Plant**

a. Statement of Issue: In its May 7th filing, Puget Sound Energy used Direct Analysis to functionalize Account 404 – Amortization of Limited Term Electric Plant, without adequate supporting information.

b. Statement of Facts: The functionalization of Account 404 – Amortization of Limited Term Electric Plant, must include a description of the account that will justify the functionalization.

c. Puget Sound Energy's Response to the Issue: Amortization of Limited Term Electric Plant costs are shown on pages 336 column (d) and pages 356 section 3 of the FERC Form 1. These account balances are input into the ASC in several different accounts on tab Sch 3 – Expenses.

The Intangible plant related portion in the amount of $1,966,305 is input to Accounts 302-303 on tab Sch 3 - Expenses. These expenses are functionalized using DIRECT analyses. Tab DIRECT Int Amort E302 and E303 in PSE's ASC Methodology Expedited Process and Consultation ASC template shows the functionalization of the amortization amount, and tab DIRECT E302 and DIRECT E303 shows the functionalization of the related assets.

d. Analysis of Position and Decision: Puget Sound Energy has provided sufficient information to support the functionalization of Account 404 – Amortization of Limited Term Electric Plant.

9. **Account 404 – Amortization of Plant Acquisition Adjustments Direct E406 and 407 - Electric WUTC AFUDC – 40600021**

a. Statement of Issue: In its May 7 filing, Puget Sound Energy functionalized Account 404 Other Regulatory Assets - Def AFUDC - Regulatory Asset to Production, Transmission and Distribution using the PTD ratio.

b. Statement of Facts: Account 404 Other Regulatory Assets - Def AFUDC - Regulatory Asset is to be functionalized using Direct Analysis. AFUDC is a component of CWIP. CWIP is functionalized to Distribution.

c. Puget Sound Energy's Response to the Issue: The regulatory asset – No. 018230031 Electric - Def AFUDC - Regulatory Asset – relates to the excess of WUTC allowed AFUDC over the amount allowed by FERC through the FERC formula. This account reflects the amortization of the regulatory asset. This amortization expense is included (unadjusted) in jurisdictional ratemaking and is recovered in rates. For purposes of the ASC Methodology Expedited Process and Consultation ASC template, the DIRECT analysis of the regulatory asset and its associated amortization expense resulted in it being functionalized to PTD to reflect the cross functional characteristics of CWIP which can be production, transmission, or distribution related construction. This functionalization may be updated if and when additional data about the underlying construction projects becomes available.

d. Analysis of Position and Decision: Puget Sound Energy shows that this account is part of their rate proceedings. However AFUDC is closed to CWIP. CWIP is not an exchangeable cost. BPA has functionalized Account 182.3 Other Regulatory Assets - Def AFUDC - Regulatory Asset to Distribution.

10. **Amortization of Plant Acquisition Adjustments Direct E406 and 407 - Elect Acquis Adj – Encogen**

a. Statement of Issue: In its May 7th filing, Puget Sound Energy used Direct Analysis to functionalize Amortization of Plant Acquisition Adjustments Direct E406 and 407 - Elect Acquis Adj – Encogen, without adequate supporting information.

b. Statement of Facts: The functionalization of Amortization of Plant Acquisition Adjustments Direct E406 and 407 - Elect Acquis Adj – Encogen, must include a description of the account that will justify the functionalization.

c. Puget Sound Energy's Response to the Issue: PSE acquired the Encogen natural gas-fired cogeneration facility in Bellingham, Washington in 1999. WUTC Docket No UE-991498 established the accounting treatment of the acquisition adjustment associated with the Encogen production asset. The acquisition adjustment for this production asset and the associated amortization expense is functionalized to production.

d. Analysis of Position and Decision: Analysis of Position and Decision: Puget Sound Energy has provided sufficient information to support the functionalization of Amortization of Plant Acquisition Adjustments Direct E406 and 407 - Elect Acquis Adj – Encogen.

SCHEDULE 3A: Taxes – no changes

SCHEDULE 3B: Other Included Items – no changes

SCHEDULE 4: Average System Cost

1. **Distribution Loss:**

a. Statement of Issue: In its filing, Puget Sound Energy used a 4.58% Distribution Loss Factor in determination of its ASC.

b. Statement of Facts: The May 7th filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years. Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

c. Puget Sound Energy's Response to the Issue: PSE's retail load loss value used in the ASC Methodology Expedited Process and Consultation ASC template was derived using a loss factor of 4.58%. This loss factor is from the loss study used by PSE in BPA Docket No. 7-A2-9501.

d. Analysis of Position and Decision: For purposes of the expedited filing, BPA completed the Distribution Loss Factor outlined in the ASCM ROD, Section 4.10.5. Puget Sound Energy did not provide a Distribution Loss Study. Puget Sound Energy's Factor has been set at 4.99%.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – no changes

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes

SUPPORTING DOCUMENTATION: Labor Ratios

1. **Maintenance of General Plant (GPM) Ratio: Miscellaneous Equipment**

a. Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

c. Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

B. <u>Identification and Analysis of Issues from comments to the July 8, 2008 ASC Draft Report</u>

SCHEDULE 1: Plant Investment/Rate Base

1. Account 183.3 – Other Regulatory Assets

a. Statement of Issue: Account 183.3 Hopkins Ridge BPA Transmission Upgrades

b. Puget Sound Energy's Response to the Issue: PSE notes that BPA included "Taxes will be functionalized to distribution" in our discussion of Account 183.3 Hopkins Ridge BPA Transmission Upgrades.

c. Analysis of Position and Decision: BPA concludes this was an error and should be removed.

SCHEDULE 1A: Cash Working Capital – no changes from July 8, 2008 report

SCHEDULE 2: Capital Structure and Rate of Return - no changes from July 8, 2008 report

SCHEDULE 3: Expenses – no changes from July 8, 2008 report

SCHEDULE 3A: Taxes – no changes from July 8, 2008 report

SCHEDULE 3B: Other Included Items – no changes from July 8, 2008 report

SCHEDULE 4: Average System Cost– no changes from July 8, 2008 report

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale

a. Statement of Issue: Treatment of the Residential Exchange Settlement Payment in the ASC Template.

b. Statement of Facts: The Residential Exchange Settlement Payment was erroneously included in Account 555 – Purchased Power as a credit and then included as a separate line item (REP reversal) in the ASC calculation.

c. Analysis of Position and Decision: The Residential Exchange Settlement Payment is not an exchangeable cost or credit. BPA therefore removed the Residential Exchange Settlement Payment (credit) from Account 555 – Purchased Power, which increased purchased power by the amount of the credit. BPA simultaneously removed the REP reversal as a separate line item in the ASC template.

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes from July 8, 2008 report

SUPPORTING DOCUMENTATION: Labor Ratios – no changes from July 8, 2008 report

C. Identification and Analysis of Issues from comments to the August 4, 2008 ASC Draft Report

SCHEDULE 1: Plant Investment/Rate Base–

1. **For Account 108, line item "Capital Leases - Common Plant" and In-Service: Depreciation of Common Plant**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

   b. Analysis of Position and Decision: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments (Electric)**, Account 114, line 92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4, 2008 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4, 2008 report

SCHEDULE 3: Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/ Rate Base*** **(Acquisition Adjustments (Electric)**, (cell E92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses:

   b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4, 2008 report

SCHEDULE 3B: Other Included – no changes from the August 4, 2008 report

SCHEDULE 4: Average System Cost - – no changes from the August 4, 2008 report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

   a. Statement of Issue: For Labor Ratio Input: line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

b. Analysis of Position and Decision: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908: all exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

D. Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC are allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that Utility's retail load during the BPA rate period. The change in ASC must meet the materiality threshold as the change in ASC resulting from adding major new resources, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more. BPA determined a change in Puget Sound Energy's ASC using the methods as described in the ASCM ROD, section 4.2.10.

Puget Sound Energy did provide New Resource Additions in its May 9, 2008, filing, but due to confidentiality issues PSE provided a privilege and confidential redacted version.

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining Puget Sound Energy's forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and Puget Sound Energy's ASCs published in the July 8, 2008 report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and Puget Sound Energy's ASCs as appropriate and as a result of Puget Sound Energy's comments to the July 8, 2008 report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and Puget Sound Energy's ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	1,355,320,900	1,368,987,966	1,386,563,292	1,407,535,341	1,429,118,492
Transmission	87,480,896	87,681,153	88,086,064	88,560,889	89,099,153
NLSL Resource Cost	0	0	0	0	0
(Less) NLSL Costs	0	0	0	0	0
Contract System Cost	**1,442,801,796**	**1,456,669,119**	**1,474,649,356**	**1,496,096,231**	**1,518,217,644**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	21,927,453	22,118,040	22,279,295	22,425,579	22,561,132
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net of NLSL)	21,927,453	22,118,040	22,279,295	22,425,579	22,561,132
Distribution Losses	1,094,180	1,103,690	1,111,737	1,119,036	1,125,800
Contract System Load	**23,021,633**	**23,221,730**	**23,391,032**	**23,544,615**	**23,686,933**

AVERAGE SYSTEM COST

ASC ($/MWh)	**$62.67**	**$62.73**	**$63.04**	**$63.54**	**$64.10**

Revised Table 2: FY 2009-2013 ASC Summary – August 4, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	1,253,780,672	1,267,291,233	1,293,645,689	1,317,595,918	1,342,581,582
Transmission	87,480,896	87,681,153	88,086,064	88,560,889	89,099,153
NLSL Resource Cost	0	0	0	0	0
(Less) NLSL Costs	0	0	0	0	0
Contract System Cost	1,341,261,568	1,354,972,386	1,381,731,753	1,406,156,807	1,431,680,735

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	21,927,453	22,118,040	22,279,295	22,425,579	22,561,132
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net of NLSL)	21,927,453	22,118,040	22,279,295	22,425,579	22,561,132
Distribution Losses	1,094,180	1,103,690	1,111,737	1,119,036	1,125,800
Contract System Load	23,021,633	23,221,730	23,391,032	23,544,615	23,686,933

AVERAGE SYSTEM COST

ASC ($/MWh)	**$58.26**	**$58.35**	**$59.07**	**$59.72**	**$60.44**

Final Table 2: FY 2009-2013 ASC Summary – September 11, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	1,287,048,182	1,299,213,211	1,324,035,089	1,346,357,375	1,369,844,418
Transmission	87,615,204	87,580,901	87,751,169	87,991,341	88,294,956
NLSL Resource Cost	0	0	0	0	0
(Less) NLSL Costs	0	0	0	0	0
Contract System Cost	1,374,663,386	1,386,794,112	1,411,786,258	1,434,348,715	1,458,139,373

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	21,927,453	22,118,040	22,279,295	22,425,579	22,561,132
(Less) NLSL	0	0	0	0	0
Total Retail Load (Net of NLSL)	21,927,453	22,118,040	22,279,295	22,425,579	22,561,132
Distribution Losses	1,094,180	1,103,690	1,111,737	1,119,036	1,125,800
Contract System Load	23,021,633	23,221,730	23,391,032	23,544,615	23,686,933

AVERAGE SYSTEM COST

ASC ($/MWh)	**$59.71**	**$59.72**	**$60.36**	**$60.92**	**$61.56**

VI. BPA STATEMENT

This ASC determination is BPAs best estimate of Puget Sound Energy's FY 2009 ASC based on the information and data provided from Puget Sound Energy during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination for FY 2009. This determination is made solely for the purpose of providing estimated FY 2009 ASCs for use in the development of BPAs FY 2009 power rates in BPAs WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such reviews will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance with the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System of Puget Sound Energy for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The Final Appendix 1 Filing, Forecast Model and NLSL assessment used to calculate Puget Sound Energy's ASCs can be viewed at BPAs ASC website: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

Snohomish PUD

Docket Number: SN-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

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TABLE OF CONTENTS

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I. FILING DATA

Utility	Parties to the Filing
Snohomish PUD 2320 California Street Everett, Washington 98201	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept.11, 2008 Final
Production Cost	$227,121,488	$226,860,355	$226,860,355	$226,860,355
Transmission Cost	$35,912,231	$35,910,723	$35,910,723	$35,910,723
(Less) New Large Single Load Costs	0	0	0	
Total Contract System Cost	$263,033,719	$262,771,078	$262,771,078	$262,771,078
Total Retail Load (MWh)	6,480,261	6,480,261	6,480,261	6,480,261
(Less) New Large Single Load	0	0	0	
Total Retail Load (Net NLSL)	6,480,261	6,480,261	6,480,261	6,480,261
Plus Distribution Losses	324,013	324,013	324,013	324,013
Total Contract System Load (MWh)	6,804,274	6,804,274	6,804,274	6,804,274
FY 2006 Base Period ASC ($/MWh)	$38.66	$38.62	$38.62	$38.62

B. FY 09 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept.11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**$37.77**	**$37.05**	**$38.08**

C. FY 09 (Exchange Period) ASC with New Resource Additions ($/MWh)

FY 2007-2009 New Resource Additions: N/A
Snohomish had no New Resource Additions.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. See 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging Utilities agreed to a number of termination agreements that provided for payments to each Utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the

REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing Utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

For more information regarding the proposed 2008 ASCM, refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. ASC Determination Process Guidelines and Expedited Review Process

The purpose of BPA's expedited review process is to estimate exchanging Utilities' ASCs for FY 2009 that could be noticed by the Administrator and incorporated into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding rely on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance to the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1.
The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a base period ASC determination, BPA used the ASC Forecast model, an excel based spreadsheet, to escalate the base year ASC forward to the effective rate period, FY 2009 (October 1, 2008 through September 30, 2009). The base year and forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capitol (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1 to determine the Utility's return on investment.

IOUs use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For COUs, the rate of return is equal to the COU's weighted cost of debt.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as described above. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items. The schedule also lists the load information, as defined below, and calculates the Utility's ASC.

Contract System Cost:
The Contract System Cost is the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Load:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any New Large Single Load(s) (NLSL).

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Sales for Resale

The Purchased Power is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1, pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A new large single load (NLSL) is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro rata basis using salary and wage data for production, transmission, and distribution/other functions included in the Utility's most recently filed Form 1. For consumer-owned utilities, comparable data is used based on the cost of service study used as the basis for retail rates at the time of review.

D. ASC Forecast

The Base Period ASC is applied to an Excel-based forecasting model to escalate the Base Year ASC data forward to the Exchange Period. For purposes of the expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Costs

Forecast Contract System Costs (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5%. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of any major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of the major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. Identification and Analysis of Issues from the May 7, 2008 ASC Appendix 1 Filing

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Costs and codes filed on May 7, 2008 by Snohomish PUD (PSE), and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base

1. **Account 303 Intangible Plant Miscellaneous - Transmission**

   a. Statement of Issue: In the May 7th filing, Snohomish PUD used Direct Analysis to functionalize this Account 303 Intangible Plant Miscellaneous, without supplying adequate support for the direct analysis.

   b. Statement of Facts: Account 303 Intangible Plant Miscellaneous sub accounts are to be functionalized using Direct Analysis with a default functionalization of Distribution.

   c. Snohomish PUDs Response to the Issue: Misc. Int. Plt. 3rd AC Intertie 303101 $8,981,368 RATE BASE Trans - This account records the PUDs ownership rights to the 3rd AC Intertie, a transmission line.

      Misc. Int. Plt. N Mtn SCL Pwr Xfr 303102 $2,809,844 RATE BASE Trans - Represents the PUDs ownership rights in the North Mountain substation owned by Seattle city light and used to serve customers in the Darrington area. This provides access to SCLs transmission.

      Misc. Int. Plt. BPA NERC Reliably 303103 $1,577,113 RATE BASE Trans - This represents the PUDs ownership rights to equipment in a BPA substation that the PUD is required to own to meet NERC reliability requirements

      - Intangible Plt. Software 5 YR 304101 $5,363,429
      - Intangible Plt. Software 8 YR 304102 $27,498,255
      - Int. Plt. Software Beyd Est. Life 304110 $15,748,189

      See Worksheet "Snohomish PUD – Data Responses" Tab SN-1 for analysis of these accounts and functionalization. Please note that during this analysis, we have identified items in these accounts which should be functionalized differently than in our original analysis.

   d. Analysis of Position and Decision: Snohomish PUD has provided sufficient information to support the functionalization of Account 303 Intangible Plant Miscellaneous.

2. **Account 124 Other Investment**

   a. Statement of Issue: In the May 7th filing, Snohomish PUD directly functionalized this account using the Cons ratio, without showing the basis of the direct assignments.

b. Statement of Facts: Account 123 Other Investment has a Direct Distribution functionalization. In addition, the Cons Ratio is no longer in use. Conservation is functionalized using Direct Analysis.

c. Snohomish PUDs Response to the Issue:

- Other Inv Coml Consv Loan 124101 $8,029
- This account records our investment in commercial Conservation loans. Conservation costs are functionalized to production per methodology endnote g.

- Other Inv Resd Consv Loan 124102 $6,961,357
- This account records our investment in residential Conservation loans. Conservation costs are functionalized to production per methodology endnote g.

- Other Inv Pwr Diversion* 124104 $4,729
- This account records a receivable from customers who have to pay back the district for theft of power.

- Other Inv Line Ext Loan* 124105 $17,344
- This account records a receivable from customers to connect a property to our grid.

- Other Inv Spec Arrangement Loans* 124107 $400 - This account records loans to customers, who, due to a meter misread have a large payable to the utility.

*Please note that during this analysis, we have identified that these items should be functionalized to Distribution/Other rather than Production.

d. Analysis of Position and Decision: Snohomish PUD used CONS ratio that functionalizes 70% to Production and 30% to Distribution. In the response to the issue, Snohomish PUD showed that $7,218,741 was directly conservation investments. The remainder of the account is distribution related.

BPA will functionalize $6,969,386 of Account 124 Other Investments to Production. The remaining $22,474 will be functionalized to Distribution. In the October 1, 2008 ASC Filing this issue will be addressed.

3. **Account 186 Deferred Debits – Production Related**

a. Statement of Issue: In the May 7th filing, Snohomish PUD directly functionalized Account 186 Deferred Debits using Direct Analysis without showing the basis of the direct assignments.

b. Statement of Facts: Account 186 Deferred Debits sub accounts are to functionalized using Direct Analysis with a default functionalization of Direct Distribution.

c. Snohomish PUDs Response to the Issue: Snohomish PUD provided the following information for the functionalization of sub accounts to Production.

- Misc. Def Debit Conservation 186114 $4,998,403
- Capitalized conservation costs. Conservation costs are allocated to production per methodology endnote g.

- Misc. Def Debit JK Re-license 186122 $2,650,137
- Capitalized relicensing costs for the Jackson Hydro Plant – Generation system costs are allocated to Production.

- Misc. Def Debit Int. Rate Swaps 186125 $18,877,515
- Mark to Market costs for Generation system long term debt. Generation system costs are allocated to Production.

- Misc. Def Debit Enron Contract 186123 $149,293,458
- Represents our potential obligation to a long – term power contract. There is a corresponding 253 credit account.

- Misc. Def Debit Est. Jackson Pwr 186107 $4,410,000
- This is an electric system receivable for Jackson Hydro Plant operations. Generation system costs are allocated to production.

- Misc. Def Debit Other Gen 186108 $2,300,000
- This is an electric system receivable for Other Generation Operating expenses. Generation system costs are allocated to production.

- Misc. Def Debit Everett Cogen. 186110 $296,000
- This is an electric system receivable for Other Generation Operating expenses. Generation system costs are allocated to production.

- Misc. Def Debit Power Contracts 186124 $198,825

d. Analysis of Position and Decision: Snohomish PUD has provided sufficient information to support the direct functionalization of Account 186 Deferred Debits.

4. **Account 243 Deferred Credits**

a. Statement of Issue: In the May 7th filing, Snohomish PUD directly functionalized this account without showing the basis of the direct assignments.

b. Statement of Facts: Account 243 - Deferred Credits sub accounts are to functionalized using Direct Analysis with a default functionalization of Direct Distribution.

c. Snohomish PUD's Response to the Issue: Snohomish PUD provided the following information for the functionalization of sub accounts to Production.

- Other Def Cr Enron Contract 253140 $149,293,458
- Represents our potential obligation to a long – term power contract. There is a corresponding 186 debit account. Power costs/credits are functionalized to Production.

- Def Cr Adv Revenue EC 253116 $712,910
- This is a generation system account which records advance revenue for the Everett Cogeneration Plant. Generation expenses/revenues are allocated to Production.

- Other Def Cr Adv Revenue JK 253118 $2,568,963
- Same as above for the Jackson Hydroelectric Plant

- Other Def Cr Adv Revenue OG 253119 $1,169,649
- Same as above for Other Generation.

d. Analysis of Position and Decision: Snohomish PUD has provided sufficient information to support the direct functionalization of Account 186 Deferred Debits.

SCHEDULE 1A: Cash Working Capital – no changes

SCHEDULE 2: Capital Structure and Rate of Return – no changes

SCHEDULE 3:

1. **Public Purpose Charge**

a. Statement of Issue: In its May 7th filing, Snohomish PUD included 7,218,741 in the Public Purpose Charge line item and functionalized this cost using the CONS ratio.

b. Statement of Facts: The Public Service Charge line item relates to the Oregon Public Purpose charge and is to be functionalized using Direct Analysis. For all conservation costs, the utility is to use Direct Analysis as the method for supporting the functionalization of conservation

c. Snohomish PUD's Response to the Issue: Snohomish PUD provided the following information for the functionalization of sub accounts to Production.

Expense Accounts

Account	Project	DESCR	SumOfSum Total Amt	Qualifies??
583102	00340398	CVR / NEEA LOAD RESEARCH	$ 112.97	*Yes*
583102	00345751	2005 GENERAL CVR - CONSERVATIO	$ 594.05	*Yes*
583102	00346261	BRIER SUB CVR UPDATES	$ 155.07	*Yes*
583102	00348134	CLEARVIEW SUBSTATION CVR MAINT	$ 6,160.23	*Yes*
583102	00349345	CLEARVIEW SUBSTATION CVR MAINT	$ 714.33	*Yes*
583102	00349346	CLEARVIEW SUBSTATION CVR MAINT	$ 5,893.19	*Yes*
583102	00350495	2006 GENERAL CVR - CONSERVATIO	$ 12,820.92	*Yes*
583102	00351576	2006 LAKE STEVENS CVR CONVERSI	$ 175.70	*Yes*
583102	00351980	LYNNWOOD CVR UPDATES	$ 1,343.45	*Yes*
583102	00351981	2006 MEADOWDALE CVR UPDATE	$ 1,225.77	*Yes*
583102	00351982	2006 MEADOWDALE CVR UPDATE	$ 7,981.13	*Yes*
583102	00352417	TULALIP CVR UPDATES	$ 2,564.02	*Yes*
583102	00352422	KELLOGG MARSH CVR UPDATES	$ 10,331.84	*Yes*
583102	00352424	HILTON LAKE CVR APPLICATION	$ 5,008.65	*Yes*
583102	00352835	CLEARVIEW SUBSTATION CVR MAINT	$ 1,610.74	*Yes*
583102	00353439	SNOHOMISH CVR MAINTENANCE	$ 8,182.97	*Yes*
583102 Total			**$ 64,875.03**	***Yes***
584102	00345751	2005 GENERAL CVR - CONSERVATIO	$ 76.93	*Yes*
584102	00350495	2006 GENERAL CVR - CONSERVATIO	$ 1,660.45	*Yes*
584102 Total			**$ 1,737.38**	***Yes***
586101	60024	Other C&I Services	$ 39,549.69	*Yes*
586101	00339361	SULTAN CVR - PLANNING, DESIGN	$ 4,008.52	*Yes*

Expense Accounts				
Account	Project	DESCR	SumOfSum Total Amt	Qualifies??
586101	00340398	CVR / NEEA LOAD RESEARCH	$ 2,206.10	*Yes*
586101	00345751	2005 GENERAL CVR - CONSERVATIO	$ 428.90	*Yes*
586101	00350495	2006 GENERAL CVR - CONSERVATIO	$ 9,256.88	*Yes*
586101 Total			**$ 55,450.09**	***Yes***
588101	00352065	SUBSTATION CAPACITOR APPLICATI	$ 151.12	*Yes*
588101 Total			**$ 151.12**	***Yes***
593101	00351576	2006 LAKE STEVENS CVR CONVERSI	$ 439.95	*Yes*
593101 Total			**$ 439.95**	***Yes***
594101	00352388	CUSTOMER GENERATION XMER DECAL	$ 140.97	*Yes*
594101 Total			**$ 140.97**	***Yes***
901101	60058	Conservation Administration	$ 352.91	*Yes*
901101	60059	NEEA Conservation	$ 15.57	*Yes*
901101 Total			**$ 368.48**	***Yes***
903101	60058	Conservation Administration	$ 209.60	*Yes*
903101 Total			$ 209.60	*Yes*
907101	60017	Public Purpose Development	$ 970.27	*Yes*
907101	60058	Conservation Administration	$ 2,193.07	*Yes*
907101	60059	NEEA Conservation	$ 594.00	*Yes*
907101 Total			**$ 3,757.34**	***Yes***
908101	60016	Customer Account Activities	$ 150.00	*Yes*
908101	60017	Public Purpose Development	$ 188,365.86	*Yes*
908101	60024	Other C&I Services	$ 3,152,363.99	*Yes*
908101	60025	Consv Loans Program	$ 22,791.56	*Yes*
908101	60039	Schools and Public Bldgs.	$ 1,879.73	*Yes*
908101	60040	Matchmaker	$ 353,361.99	*Yes*
908101	60041	Appliance Rebates	$ 895,427.39	*Yes*
908101	60042	Compact Florescent Light Prog	$ 858,869.84	*Yes*
908101	60044	C&I Benchmarking	$ 3,258.79	*Yes*
908101	60045	New Construction-Commercial	$ 5,027.59	*Yes*
908101	60046	New Construction-Residential	$ 28,963.43	*Yes*
908101	60050	Vendor Miser Energy Efficiency	$ 1,969.41	*Yes*
908101	60052	Residential Heat Pump Incentiv	$ 57,000.00	*Yes*
908101	60053	Retail Green Power Planet Pwr	$ 82,463.18	*Yes*
908101	60056	Housing Improvement Prgm (HIP)	$ 322,068.99	*Yes*
908101	60058	Conservation Administration	$ 235,925.22	*Yes*
908101	60059	NEEA Conservation	$ 183,167.08	*Yes*

Expense Accounts

Account	Project	DESCR	SumOfSum Total Amt	Qualifies??
908101	60060	Consv Cust Acct Activities	$ 32,165.33	*Yes*
908101	60061	Customer Renewables	$ 1,548.46	*Yes*
908101	60063	Refrigerator Recycle Program	$ 530,854.06	*Yes*
908101	60064	Seattle Fndtn Mobile Home Prog	$ 47,504.33	*Yes*
908101	60066	Biodigester - Qualco Energy	$ 4,680.68	*Yes*
908101	66005	Verify, Evaluate Measurement	$ 27,358.08	*Yes*
908101	00327985	PLANET POWER MARKETING	$ 32,163.83	*Yes*
908101	00327986	PLANET POWER IMPLEMENTATION	$ 3,513.96	*Yes*
908101	00328396	SERVICES TOR SNOHOMISH SCHOOL	$ 3,683.95	*Yes*
908101	00328397	SERVICES TOR MARYSVILLE SCHOOL	$ 3,185.77	*Yes*
908101 Total			**$ 7,079,712.50**	***Yes***
909101	60053	Retail Green Power Planet Pwr	$ 1,815.98	*Yes*
909101 Total			**$ 1,815.98**	***Yes***
913101	60063	Refrigerator Recycle Program	$ 261.00	*Yes*
913101 Total			**$ 261.00**	***Yes***
920101	60066	Biodigester - Qualco Energy	$ 9,490.31	*Yes*
920101 Total			**$ 9,490.31**	***Yes***
921101	60017	Public Purpose Development	$ 330.75	*Yes*
921101 Total			$ 330.75	Yes
Grand Total			$ 7,218,740.50	

d. Analysis of Position and Decision: The information provided by Snohomish PUD supports the functionalization of the Public Purpose Charge with 70% functionalized to Production and 30% functionalized to Distribution.

In the October 1, 2008 ASC filing all conservation costs will be functionalized using Direct Analysis.

2. **Account 404 - Amortization of Intangible Plant Miscellaneous**

a. Statement of Issue: In its May 7th filing, Snohomish PUD functionalized Account 404 – Amortization of Intangible Plan Miscellaneous using Direct Analysis, without sufficient information to support the functionalization.

b. Statement of Facts: Functionalization using Direct Analysis for Account is required. The default functionalization is Direct Distribution. Direct

Analysis must be supported with sufficient details of the account and justification of the functionalization.

c. Analysis of Position and Decision: Snohomish PUD did not respond to the issues list regarding the use of Direct Analysis for Account 404-Anirtuzation of Intangible Plant Miscellaneous.

In the October 1, 2008 ASC filing the use of Direct Analysis will be accompanied by sufficient information to support the proposed functionalization of Account 404-Anirtuzation of Intangible Plant Miscellaneous.

SCHEDULE 3A: Taxes – no changes

SCHEDULE 3B: Other Included Items – no changes

1. **Sales for Resale MWhs**

a. Statement of Issue: In its May 7th filing, Snohomish PUD did not provide the Sales for resale MWhs value in ASC Template.

b. Statement of Facts: Snohomish provided the MWhs.

c. Analysis of Position and Decision: Adjusted the Sales for Resale to reflect 2,105,474 MWhs

SCHEDULE 4: Average System Cost

1. **Distribution Loss:**

a. Statement of Issue: In its May 7th filing, Snohomish PUD used a 5% Distribution Loss Factor in determination of its ASC.

b. Statement of Facts: The May 7th filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years. Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

c. Analysis of Position and Decision: For purposes of the expedited filing, BPA was unable to provide a Distribution Loss Study. BPA will use the 5% Distribution Loss Factor that was included in Snohomish PUD's May 7th filing.

2. **Contract System Loads:** New Large Single Load (NLSL) – None - No changes

3. **Contract System Costs:** New Large Single Load (NLSL) Costs - None- No changes

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – no changes

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes

SUPPORTING DOCUMENTATION: Labor Ratios

1. **Maintenance of General Plant (GPM) Ratio:** Miscellaneous Equipment

a. Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

c. Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

B. Identification and Analysis of Issues from comments to the July 8, 2008 ASC Draft Report

SCHEDULE 1: Plant Investment/Rate Base– no changes from July 8, 2008 report

SCHEDULE 1A: Cash Working Capital – no changes from July 8, 2008 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from July 8, 2008 report

SCHEDULE 3: – no changes from July 8, 2008 report

SCHEDULE 3A: Taxes – no changes from July 8, 2008 report

SCHEDULE 3B: Other Included – no changes from July 8, 2008 report

SCHEDULE 4: Average System Cost - – no changes from July 8, 2008 report

SUPPORTING DOCUMENTATION – no changes from July 8, 2008 report

C. Identification and Analysis of Issues from comments to the August 4, 2008 ASC Draft Report

SCHEDULE 1: Plant Investment/Rate Base–

1. For Account 108, line item "**Capital Leases - Common Plant"** and **In-Service: Depreciation of Common Plant**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

   b. Analysis of Position and Decision: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments** (**Electric)**, Account 114, line 92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4 2008 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4 2008 report

SCHEDULE 3: – Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/Rate Base* (Acquisition Adjustments (Electric)**, (cell E92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses:

   b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4 2008 report

SCHEDULE 3B: Other Included – no changes from the August 4 2008 report

SCHEDULE 4: Average System Cost - – no changes from the August 4 2008 report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

   a. Statement of Issue: For Labor Ratio Input: line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

   b. Analysis of Position and Decision: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908: all exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

D. Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC are allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that Utility's retail load during the BPA rate period. The change in ASC must meet the materiality threshold as the change in ASC resulting from adding major new resources, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more. Snohomish did not have any New Resource Additions.

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining Snohomish County PUD forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and Snohomish County PUD ASCs published in the July 8, 2008 report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and Snohomish County PUD ASCs as appropriate and as a result of Snohomish County PUD comments to the July 8, 2008 report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and Snohomish County PUD ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	237,521,129	237,813,973	249,293,862	261,452,214	264,945,059
Transmission	37,611,796	37,979,200	38,471,842	39,017,404	39,600,659
NLSL Fully Allocated Cost ($/MWh)					
(Less) NLSL Costs	0	0	0	0	0
Total Contract System Cost	**275,132,925**	**275,793,173**	**287,765,704**	**300,469,618**	**304,545,718**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
(Less) NLSL					
Total Retail Load (Net or NLSL)	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
Distribution Loss	346,873	351,704	354,636	357,506	360,114
Total Contract System Load	**7,284,334**	**7,385,777**	**7,447,346**	**7,507,618**	**7,562,386**

AVERAGE SYSTEM COST

ASC ($/MWh)	**37.77**	**37.34**	**38.64**	**40.02**	**40.27**

Revised Table 2: FY 2009-2013 ASC Summary – August 4, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	232,339,854	244,308,235	247,588,656	260,587,973	263,899,001
Transmission	37,611,796	37,979,200	38,471,842	39,017,404	39,600,659
NLSL Fully Allocated Cost ($/MWh)					
(Less) NLSL Costs					
Total Contract System Cost	269,951,649	282,287,435	286,060,497	299,605,377	303,499,660

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
(Less) NLSL					
Total Retail Load (Net or NLSL)	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
Distribution Loss	346,873	351,704	354,636	357,506	360,114
Total Contract System Load	7,284,334	7,385,777	7,447,346	7,507,618	7,562,386

AVERAGE SYSTEM COST

ASC ($/MWh)	37.06	38.22	38.41	39.91	40.13

Final Table 2: FY 2009-2013 ASC Summary – September 11, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	239,609,815	254,546,263	257,833,058	274,327,600	277,644,989
Transmission	37,780,520	38,148,568	38,641,922	39,188,191	39,772,181
NLSL Fully Allocated Cost ($/MWh)					
(Less) NLSL Costs					
Total Contract System Cost	277,390,335	292,694,831	296,474,980	313,515,790	317,417,170

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
(Less) NLSL					
Total Retail Load (Net or NLSL)	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
Distribution Loss	346,873	351,704	354,636	357,506	360,114
Total Contract System Load	7,284,334	7,385,777	7,447,346	7,507,618	7,562,386

AVERAGE SYSTEM COST

ASC ($/MWh)	**38.08**	**39.63**	**39.81**	**41.76**	**41.97**

VI. BPA STATEMENT

This ASC determination is BPAs best estimate of Snohomish's FY 2009 ASC based on the information and data provided from Snohomish during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination for FY 2009. This determination is made solely for the purpose of providing estimated FY 2009 ASCs for use in the development of BPAs FY 2009 power rates in BPAs WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such reviews will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance with the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System of Snohomish for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The Final Appendix 1 Filing, Forecast Model and NLSL assessment used to calculate Snohomish's ASCs can be viewed at BPAs ASC website: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

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