PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

December 30, 2009

VIA ELECTRONIC FILING

Washington Utilities and Transportation Commission
1300 S. Evergreen Park Drive SW
P.O. Box 47250
Olympia, WA 98504-7250

Attention: David W. Danner
Executive Director and Secretary

RE: **Advice No 09-06**
Schedules of Estimated Avoided Cost and
Update to Schedule 37 – Avoided Cost Purchases from Cogeneration and Small Power Purchases

Dear Mr. Danner:

Pursuant to RCW 80.28.050 and 80.28.060, WAC 480-107-055 and WAC 480-107-095 and the Washington Utilities and Transportation Commission's ("Commission") Rules and Regulations, PacifiCorp, d.b.a. Pacific Power, ("Company") submits for filing a copy of the proposed tariffs applicable to Pacific Power's electric service in the state of Washington. PacifiCorp respectfully requests an effective date of February 12, 2010.

Fifth Revision of Sheet No. 37.2	Schedule 37	Avoided Cost Purchases from Cogeneration and Small Power Production

The Company's current avoided cost prices and Schedule 37 became effective in February 2009. Since that time resource requirements, natural gas and market prices have changed, as have the Company's avoided costs. This filing is being made to update the Company's estimated avoided cost prices and Schedule 37 based on the costs that the Company would expect to pay but for the QF resource.

It is respectfully requested that all formal correspondence and Staff requests regarding this filing be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon, 97232

Informal questions should be directed to Cathie Allen, Regulatory Manager, at (503) 813-5934.

Sincerely,

Andrea L. Kelly /ca

Andrea L. Kelly
Vice President, Regulation

Enclosures

Attachments and Exhibits
Attachment A: Notice
Attachment B: Summary Page of Tariffs
Attachment C: Proposed Tariff Schedule 37
Exhibit 1: Summary of the Company's avoided cost calculation methodology

ATTACHMENT A

Attachment A

NOTICE
PACIFIC POWER

Pursuant to Washington Law (including without limitation RCW 80.28.050 and -060) and the Washington Utilities and Transportation Commission's (the "Commission") Rules & Regulations, Pacific Power has filed with the Commission the original tariff schedules for electric service in the State of Washington.

Overview

Pacific Power's (the "Company") current avoided cost prices became effective in February 2009. Since that time resource requirements, natural gas and market prices have changed as have the Company's avoided costs. This filing is being made to bring the Commission approved avoided cost prices in line with the costs that the Company would expect to pay but for the QF resource.

The Commission will examine the Company's proposed tariff sheets. As a result of such examination, the Commission may determine that any or all of said schedules should be accepted as filed, modified or rejected.

Unless suspended by the Commission, these tariff sheets will become effective February 12, 2010.

DATED: December 30, 2009

PACIFIC POWER

By Andrea L. Kelly /ca
Andrea L. Kelly
Vice President, Regulation
Pacific Power

ATTACHMENT B

The proposed tariff sheets to be revised in Pacific Power's currently effective Tariff WN U-74 are designated as follows:

Fifth Revision of Sheet No. 37.2	Schedule 37	Avoided Cost Purchases from Cogeneration and Small Power Production

ATTACHMENT C

EXHIBIT 1

PACIFIC POWER
AVOIDED COST CALCULATION

WASHINGTON - DECEMBER 2009

PACIFIC POWER
AVOIDED COST CALCULATION

WASHINGTON - DECEMBER 2009

The starting point for the avoided cost calculation is the load and resource balance developed for the Company's 2008 Integrated Resource Plan (IRP). It should be noted that many of the input assumptions for the IRP were fixed in November 2008, in order to enable filing of the IRP in May 2009. Due to the age of the input assumptions, many of the inputs have been updated for known changes for purposes of this avoided cost calculation. The avoided cost prices were also developed consistent with the west control area allocation methodology adopted for the Company in Docket No. UE-061546.

Loads and Resources

The Company's October 2009 load forecast was used in the study.

Long-term sales and purchase contracts were updated to include information available as of December 2009. These changes include the addition or revision of several long-term purchase contracts[1].

Table 1 presents the Company's western control area loads and resource balance. Table 1 shows an energy balance with a surplus of 488 aMW in 2010 declining to a surplus of 326 aMW in 2014. The winter peak has a capacity deficit of 73 MW in 2010, a surplus of 109 MW in 2011 and a capacity deficit of over 600 MW in 2012 through 2014. The summer months have two years of surplus - 2010 and 2011 followed by a capacity deficit of over 800 MW in 2012 through 2014. The change in capacity position is primarily caused by the expiration of the BPA Peaking contract in August 2011.

Avoided Cost Calculation

Based on the load and resource balance, the avoided cost calculation is separated into two distinct periods: (1) the Short Run – a period of resource sufficiency in which the avoided costs are based on the marginal production cost of existing resources plus the cost of purchasing summer capacity; and (2) the Long Run – a resource deficit period in which new resources are required to provide both capacity and energy to meet the Company's resource requirements. Avoided costs during the deficit period are based on the cost of a combined cycle combustion turbine. The load and resource balances in **Table 1** indicate resource sufficiency for all five years, only Short Run avoided costs are included in the current study.

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[1] Additions and revisions to the long-term contracts portfolio include the addition of a Pacific Gas and Electric sale contract and an Idaho Power purchase contract. The Weyerhaeuser Reserve contract has been removed. Included is a new adjustment for Lewis River loss of efficiency and motoring loss and the addition of Seattle City Light State Line reserves. Short term firm transmission capacity was included.

Short Run Avoided Costs

During periods of resource sufficiency, avoided energy costs are based on the displacement of purchased power and existing thermal resources calculated by the Company's GRID model. The model input data includes the monthly load and resource data, which are the basis for the annual summary of loads and resources shown in **Table 1**. To calculate short-run avoided costs, two production cost studies are prepared. The only difference between the two studies is an assumed 50 aMW zero running cost system resource. The 50 aMW resource is a proxy for qualifying facility generation. The avoided energy cost is the difference between the two studies. The outputs of the production cost model run are provided as **Table 2**.

Winter capacity costs during the Short Run period are based on three-month capacity purchases. The annual value as shown in **Table 3** is one-fourth of the total fixed costs of a simple cycle combustion turbine (SCCT). Because energy generated by a qualifying facility may vary, avoided costs at 75%, 85% and 95% capacity factors are prepared to illustrate the impact of differing generation levels. This calculation is also shown in **Table 3**.

Avoided energy costs can be differentiated between on-peak and off-peak periods. To make this calculation, the Company assumed that all capacity costs are incurred to meet on-peak load requirements. On an annual basis, approximately 57% of all hours are on-peak and 43% are off-peak. **Table 4** shows the calculation of on-peak and off-peak avoided energy prices.

For informational purposes, **Table 5** shows a comparison between the avoided costs currently in effect in Washington and the proposed avoided costs in this filing.

Table 6 shows the calculation of the total fixed costs of a SCCT that are used in **Table 3**.

Table 1
Loads and Resources
2010 through 2019

	2010	2011	2012	2013	2014
aMW					
Net Load	2,249	2,276	2,325	2,350	2,360
Long Term Sales	169	169	169	94	94
Short Term Firm Sales	132	16	5	-	-
Total Requirements	2,550	2,461	2,499	2,444	2,454
Long Term Purchases	467	441	357	364	364
Short Term Firm Purchase	115	-	-	-	-
Thermal Generation	1,904	1,904	1,904	1,904	1,904
Other Generation	562	550	544	527	531
Reserves	(9)	(12)	(29)	(21)	(18)
Total Resources after Reserves	3,038	2,883	2,777	2,775	2,781
Surplus / (Deficit)	488	422	278	331	326
Percent Surplus / (Deficit)	19.1%	17.2%	11.1%	13.5%	13.3%
Peak (July)					
Net Load	3,309	3,360	3,462	3,484	3,511
Long Term Sales	463	463	463	463	463
Short Term Firm Sales	175	-	-	-	-
Total Requirements	3,947	3,823	3,924	3,946	3,974
Long Term Purchases	1,402	1,285	629	628	508
Short Term Firm Purchase	478	-	-	-	-
Thermal Generation	1,957	1,957	1,957	1,957	1,957
Other Generation	1,060	1,057	975	996	1,014
Reserves	(470)	(467)	(470)	(469)	(471)
Total Resources after Reserves	4,427	3,832	3,090	3,111	3,008
Surplus / (Deficit)	480	9	(834)	(835)	(966)
Percent Surplus / (Deficit)	12.2%	0.2%	-21.3%	-21.2%	-24.3%
Peak (January)					
Net Load	3,653	3,663	3,712	3,774	3,806
Long Term Sales	200	200	200	100	100
Short Term Firm Sales	275	-	-	-	-
Total Requirements	4,128	3,863	3,912	3,874	3,906
Long Term Purchases	1,285	1,256	469	503	519
Short Term Firm Purchase	78	-	-	-	-
Thermal Generation	2,027	2,027	2,027	2,027	2,027
Other Generation	1,140	1,134	1,149	1,177	1,202
Reserves	(477)	(445)	(462)	(438)	(488)
Total Resources after Reserves	4,054	3,971	3,183	3,270	3,261
Surplus / (Deficit)	(73)	109	(729)	(604)	(646)
Percent Surplus / (Deficit)	-1.8%	2.8%	-18.6%	-15.6%	-16.5%

Table 2
Avoided Costs ($/MWh)
Non-Firm Energy

Year	Winter Season					Summer Season				Winter Season		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GRID Production Cost Study												
2010	50.48	47.53	40.98	38.23	31.27	29.92	44.76	50.73	50.55	48.73	55.38	59.84
2011	57.94	57.05	52.44	45.37	31.81	30.55	46.14	57.94	52.89	52.04	55.89	60.16
2012	58.79	58.17	53.76	45.39	32.33	30.34	46.22	58.60	53.38	53.37	56.54	60.60
2013	58.29	58.57	54.05	46.04	32.75	30.43	47.25	59.03	54.08	53.76	56.94	61.00
2014	59.76	59.50	53.94	46.98	33.68	31.79	48.62	59.47	54.87	53.12	57.60	62.16

Annual Seasonal Average

	Winter Season	Summer Season	Annual Average
2010	$46.55	$43.99	$45.70
2011	$51.59	$46.88	$50.02
2012	$52.37	$47.13	$50.62
2013	$52.67	$47.70	$51.02
2014	$53.34	$48.69	$51.79

Source GRID Production Cost Study

Table 3
Total Avoided Cost

Year	Avoided Firm Capacity Costs	Total Avoided Energy Cost	Total Avoided Costs At Stated Capacity Factor		
			75%	85%	90%
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
			(b)+((a)/8.76 x 0.75)	(b)+((a)/8.76 x 0.85)	(b)+((a)/8.76 x 0.9)
Avoided Resource					
2010	$21.76	$45.70	$49.01	$48.62	$48.46
2011	(1)	$50.02	$50.02	$50.02	$50.02
2012	$22.58	$50.62	$54.06	$53.66	$53.49
2013	$22.98	$51.02	$54.51	$54.10	$53.93
2014	$23.39	$51.79	$55.35	$54.93	$54.76

Columns

(a) Table 6 Column (f) for three months (multiplied by 3/12)

(b) Table 2 Annual Average

Note: (1) No capacity payment is made in 2011 because the Company is capacity surplus during the winter peak 2011.

Table 4
On- & Off- Peak Energy Prices

Year	Avoided Firm Capacity Costs	Capacity Cost Allocated to On-Peak Hours	Total Avoided Energy Cost	On-Peak 4,993 Hours	Off-Peak 3,767 Hours
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
		(a) /(8.76 x 21.0% x 57%)		(b) + (c)	(c)
Avoided Resource					
2010	$21.76	$20.75	$45.70	$66.45	$45.70
2011	(1)		$50.02	$50.02	$50.02
2012	$22.58	$21.53	$50.62	$72.15	$50.62
2013	$22.98	$21.92	$51.02	$72.93	$51.02
2014	$23.39	$22.31	$51.79	$74.10	$51.79

Columns

(a) Table 3 Column (a)

(b) Table 6 21.0% is the on-peak capacity factor of the SCCT Proxy Resource

(c) Table 3 Column (b)

Note: (1) No capacity payment is made in 2011 because the Company is capacity surplus during the winter peak 2011.

Table 5
Comparison between Proposed and Current Avoided Costs

Year	Total Avoided Costs at 85% CF		
	Proposed Avoided Costs ($/MWh)	Washington Approved Avoided Costs ($/MWh)	Difference ($/MWh)
	(a)	(b)	(c) (a) - (b)
2009		$58.60	
2010	$48.62	$63.69	-$15.06
2011	$50.02	$63.73	-$13.71
2012	$53.66	$64.60	-$10.94
2013	$54.10	$65.84	-$11.74
2014	$54.93		
Levelized Prices $/MWH (Nominal) @ 7.1% Discount Rate (1)			
5 Year (2009 - 2013)		63.08	
5 Year (2010 - 2014)	52.04		

Columns

(a) Table 3 Column (d)

(b) Avoided Costs Approved by the Commission February 13, 2009

Note (1): Discount Rate - Company Official Discount Rate - Dated September 2009

Table 6
Total Cost of Displaceable Resources
SCCT Frame (2 Frame "F") - West Side Options (1500')

Year	Estimated Capital Cost $/kW	Capital Cost at Real Levelized Rate $/kW-yr	Fixed O&M $/kW-yr	Variable O&M $/MWh	Total O&M at Expected CF $/kW-yr	Total Resource Fixed Costs $/kW-yr
	(a)	(b)	(c)	(d)	(e)	(f)
2008	$679	$58.53	$3.90	$12.63	$27.13	$85.66
2009		$58.76	$3.92	$12.68	$27.25	$86.01
2010		$59.47	$3.97	$12.83	$27.57	$87.04
2011		$60.60	$4.05	$13.07	$28.09	$88.69
2012		$61.69	$4.12	$13.31	$28.61	$90.30
2013		$62.80	$4.19	$13.55	$29.12	$91.92
2014		$63.93	$4.27	$13.79	$29.64	$93.57

Source: (a)(c)(d) Plant Costs 2008 IRP (Table 6.3 and 6.5)
(b) = (a) x Payment Factor
(e) = (d) x (8.76 x 21%) + (c)
(f) = (b) + (e)

SCCT Frame (2 Frame "F") - West Side Options (1500')		
338	Plant capacity	MW
$ 679	Plant capacity cost	$/kW
$ 3.90	Fixed O&M plus on-going capital cost	$/kW-yr
$ 12.63	Variable O&M and Other Costs	$/MWH
$ 8.56	Fixed Pipeline Costs Included Above	$/MWH
8.62%	Payment Factor	
21%	Capacity Factor	

Company Official Inflation Forecast - Dated September 2009	
2009	0.40%
2010	1.20%
2011	1.90%
2012	1.80%
2013	1.80%
2014	1.80%