Oregon
Theodore R. Kulongoski, Governor

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July 14, 2009

Via Electronic Filing and U.S. Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: **Docket No. UE 207 – In the Matter of PACIFICORP, dba PACIFIC POWER 2010 Transition Adjustment Mechanism.**

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Reply Redacted Testimony.

/s/ Kay Barnes
Kay Barnes
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
(503) 378-5763
Email: kay.barnes@state.or.us

c: UE 207 Service List (parties)

PUBLIC UTILITY COMMISSION
OF OREGON

UE 207

STAFF REPLY TESTIMONY OF

KELCEY BROWN
MICHAEL DOUGHERTY

In the Matter of
PACIFICORP, dba PACIFIC POWER
2010 Transition Adjustment Mechanism

REDACTED
July 14, 2009

CASE: UE 207
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Reply Testimony

July 14, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Kelcey Brown. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am a Senior Economist in the Electric and Natural Gas Division of the Utility Program of the Public Utility Commission of Oregon (OPUC).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will provide Staff's recommended adjustments to the net variable power costs (NVPC) PacifiCorp filed in its annual Transition Adjustment Mechanism (TAM).

Q. PLEASE PROVIDE A SUMMARY OF STAFF'S ADJUSTMENTS IN THIS TAM FILING.

A. Staff recommends the following adjustments (on an Oregon allocated basis) to PacifiCorp's filed net power cost request of $20,571,645.[1]

1. A reduction of $5,361,081 to NVPC associated with PacifiCorp's Coal Fuel Burn Expense.
2. A reduction of approximately $3,401,100 to NVPC due to increased generation at the PacifiCorp Hydro facilities Bear Creek, Tokatee, and JC Boyle associated with an adjustment to normalized forecasting.

[1] *See* Exhibit PPL/302, Ridenour/1.

3. A reduction of approximately $1,404,296 to NVPC due to increased generation at the Condit hydro plant associated with expected continued operation through 2010.
4. A reduction of approximately $564,551 to NVPC to eliminate double recovery of Operation and Maintenance costs (O&M) the Company inappropriately included in this year's TAM filing.
5. I recommend that the Commission require the Company to modify its Open Access Transmission Tariff with the Federal Energy Regulatory Commission (FERC) associated with providing wind integration services to non-owned wind facilities.

These adjustments total $10,731,028 on an Oregon allocated basis. In addition, I recommend that the Commission require PacifiCorp to update its "Other Revenue" account for those items that have a direct relation to variable power costs filed within the TAM proceedings. In making this recommendation, I am not suggesting any adjustment to base rates in UE 210, PacifiCorp's current rate filing.

Q. DO YOU WISH TO INTRODUCE AN ADDITIONAL STAFF WITNESS IN THIS TAM PROCEEDING?

A. Yes. Staff witness Michael Dougherty provides testimony supporting the adjustment to PacifiCorp's fuel burn expense in Staff/200, Dougherty/1-25.

Q. PLEASE PROVIDE A SUMMARY OF STAFF'S ADJUSTMENTS TO PACIFICORP'S FUEL BURN EXPENSE.

A. Staff's first adjustment, a reduction to PacifiCorp's fuel burn expense, is based on two types of adjustments: PacifiCorp's forecasted coal price and a lower of cost or market analyses, pursuant to Oregon Administrative Rule (OAR) 860-027-0048, Allocation of Costs by an Energy Utility. With respect to PacifiCorp's forecasted coal price, based on information provided by the Energy Information Administration (EIA), Staff has substituted the PacifiCorp forward market price with the EIA price, escalated. Staff does not agree with PacifiCorp's forward market price, it is significantly higher than current estimates, and in recent months has seen even further indications of a continued decline in the spot market price of coal.[2] This substitution of prices results in a reduction to the fuel burn expense at the Dave Johnston Coal plant.

Staff's second adjustment pertains to the application of the Oregon Administrative Rules, which states that when an affiliate entity provides services to a regulated entity those services will be recorded at the lower of cost or market rate. In Staff/200, Staff witness Michael Dougherty will show that PacifiCorp's coal prices from affiliate mines is above market; therefore, Staff's recommended adjustment reflects the market value of coal for test period 2010 versus PacifiCorp's requested coal costs. This adjustment is reflected in a reduction to the fuel burn expense at the Jim Bridger and Huntington Coal plants.

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[2] *See* EIA Short-term Energy Outlook, http://www.eia.doe.gov/steo, June 9, 2009.

Q. PLEASE SUMMARIZE STAFF'S PROPOSED ADJUSTMENTS TO NORMALIZE HYDRO GENERATION AT THE BEAR CREEK, TOKATEE AND J.C. BOYLE HYDRO PLANTS.

A. PacifiCorp has proposed a significant decline in its overall hydro generation. In PPL(TAM)/100/Duvall/6, Mr. Duvall estimates the impact of the reduction in hydro generation from Company-owned facilities at approximately $19 million. After looking at the Company's forecast of its hydro operations, Staff finds that the Company has substituted a forecast of its hydro production, taking into consideration recent droughts, and other changes to its forecast that Staff does not believe are consistent with the Commissions general practice of long term normalization of hydro production.

Q. PLEASE SUMMARIZE STAFF'S PROPOSED ADJUSTMENT TO HYDRO GENERATION AT THE CONDIT HYDRO PLANT.

A. PacifiCorp provided information in Staff Data Request No. 56[3] that indicates the Condit dam will continue operations through October 2010. PacifiCorp's TAM filings have reflected this renewal of operations through October of the test year in every year since 2006, while in reality it has operated every year since 2006 for the full 12 months. Staff recommends that the Condit facility be reflected as running for the entire calendar year of 2010.

Q. PLEASE SUMMARIZE STAFF'S PROPOSED ADJUSTMENTS ASSOCIATED WITH "ADDITIONAL O&M."

[3] See Exhibit Staff/103, Brown/2-7 (Confidential).

A. PacifiCorp has included "Additional O&M" on its gas-fired facilities in this filing for the first time. Staff believes that these additional O&M costs are duplicative to the O&M costs currently requested in PacifiCorp's general rate case.

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATION ASSOCIATED WITH THE LONG HOLLOW WIND FACILITY.

The Long Hollow Wind facility is a non-owned wind facility connected to PacifiCorp's transmission system through the Company's Open Access Transmission Tariff (OATT). At this time the Company has not sought an additional tariff, or a change in the existing tariff to the Federal Energy Regulatory Commission (FERC) that would allow it to charge the facility for the wind integration services that the Company is providing.

<u>Hydro Adjustment</u>

Q. HAS THE COMPANY PROVIDED ANY INDICATION THAT IT HAS CHANGED ITS MODELING METHODOLOGY FROM THAT USED IN UE 199 FOR ITS HYDRO FACILITIES?

A. Yes. In response to Staff Data Request No. 59[4] the Company states that it has changed its methodologies from UE 199 "…in order to decrease potential modeling volatility and align with actual project operations."

Q. DOES STAFF EXPECT THAT LONG TERM AVERAGES USED IN HYDRO MODELING, SUCH AS 30 OR 40 YEARS, WOULD PRODUCE SIGNIFICANT VOLATILITY FROM YEAR TO YEAR?

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[4] See Exhibit Staff/103, Brown/1.

A. No. The Company's current method of "aligning with actual project operations" is actually causing significant volatility year over year. For example, the modeling of the Bear River hydro complex has realized a decline of 130,00 MWh, which is a 43 percent drop as compared to UE 199. The J.C. Boyle facility is down by 47,000 MWh, a 12 percent drop, but in the prior filing the facility had a 7 percent increase. These types of swings are indicative of the Company making short term adjustments to its hydro forecasts.

Q. SINCE THE J.C. BOYLE FACILITY, LOCATED ON THE KLAMATH RIVER, USES HISTORICAL NATURAL INFLOW INPUTS FROM THE MOST RECENT 40 WATER YEARS, IS IT REASONABLE TO EXPECT THIS TYPE OF UP AND DOWN MOVEMENT IN A 40 YEAR NORMALIZED FORECAST?

A. No. In Staff Data Request No. 56[5] the Company provided the "PacifiCorp Hydro Generation Long Term Resource Model" that includes a tab with detailed notes on each hydro facility and river system that documents each change to the forecast of the facilities. Staff expected to find a change in the licensing agreement, improvements or degradation of the facility, or a significant planned outage event. There are no notes or indications of recent changes that would cause either the J.C. Boyle or Tokatee facility to realize such a significant decline in output.

Q. HAS THE COMPANY PROVIDED A REASON FOR THE 43 PERCENT DROP AT THE BEAR RIVER HYDRO COMPLEX?

[5] See Exhibit Staff/103, Brown/2-7 (confidential).

A. Yes. In response to Staff Data Request No. 60[6] the Company indicated that the Bear River hydro complex is currently impacted by a drought, and that it expects the drought to continue for the next three years. Based on this expectation of continued drought the Company has excluded flood control years from historic database used to normalize generation.

Q. IS IT REASONABLE FOR THE COMPANY TO MAKE THESE TYPES OF ADJUSTMENTS TO ITS NORMALIZED HYDRO GENERATION?

A. No. The adjustments that have been made to J.C. Boyle, Tokatee, and Bear Creek are not consistent with standard hydro normalization practice. The Commission has indicated in several proceedings that over the course of a hydro forecast there will be variations in actual versus forecast. These variations are expected, but over time will average out. For the Company to make modifications to the long term average because it believes that short term operations are going to be different due to weather or expected water is inappropriate.

Q. HAS THE COMPANY MODELED THE CONDIT HYDRO FACILITY FOR THE 2010 TEST YEAR?

A. No. At PPL(TAM)/100/Duvall/6, Mr. Duvall states that the Condit dam operating license has expired. However, in response to Staff Data Request No. 56[7] the Company references an e-mail dated March 16, 2009 indicating that the facility will continue operations through October 1, 2010.

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[6] See Exhibit Staff/103, Brown/8.
[7] See Exhibit Staff/103, Brown/3 (Confidential).

Q. IS THIS THE FIRST YEAR THAT THE CONDIT FACILITY HAS UNDERGONE AN ANNUAL RENEWAL THROUGH OCTOBER OF THE FOLLOWING YEAR?

A. No. Every year since 2006, the Company indicated that the Condit hydro facility would shutdown by October 1 of the test year; however, Condit's license has been renewed each year. The Company has not been able to accurately predict when this facility will discontinue operations. Therefore, Staff recommends that Condit be included in rates in every month of the 2010 test year.

Q. HOW HAS STAFF CALCULATED ITS PROPOSED HYDRO ADJUSTMENT?

A. Staff asked the Company to provide the power cost impact of its adjustments to the hydro forecast. The Company replied in Staff Data Request No. 60 that it had not performed this study. Therefore, Staff took the change in Megawatt hours (MWh) from UE 199, a total of 285,058 MWh, and multiplied this by the average annual forward price curve provided in PacifiCorp work papers.[8] This dollar amount is an approximation of the potential cost impact of including this generation into the GRID model.

Additional O&M

Q. PLEASE DESCRIBE PACIFICORP'S ADDITIONAL O&M COSTS.

[8] See Exhibit Staff/102, Brown/1.

A. According to the Company, when gas turbines are cycled off-line, the cycling of the components has a detrimental effect on the turbine components. In Staff Data Request No. 69 the Company claims that "General industry belief is that the approximate cost of this impact is around $10,000 - $12,000 per start depending upon the particular gas turbine manufacturer."[9]

Q. IS THE COMPANY CURRENTLY COLLECTING O&M EXPENSES IN BASE RATES?

A. Yes. In addition, the Company has filed for increased generation O&M expenses in its current general rate case filing at the Commission, UE 210.

Q. HOW DOES THE COMPANY CALCULATE ITS O&M EXPENSE FOR PURPOSES OF THE GENERAL RATE CASE FILING?

A. In UE 210 (the Company's general rate case), PacifiCorp uses a historical base period of twelve months ending June 2008, forecasted to a calendar year 2010 test period. The expenses are not budgeted or forecasted based on the Company's TAM filing, or modeled starts.

Q. PLEASE DISCUSS THE COMPANY'S CALCULATION OF ADDITIONAL O&M.

A. The Company calculates additional O&M using two GRID model runs[10], one that is referred to as the "base" model run, and a second that uses "screens" to more accurately dispatch the gas-fired facilities. For example, the base model run would have the Chehalis facility running all day and all night in certain time frames, when in actuality these units would be cycled off-line during the night

[9] See Exhibit Staff/103, Brown/9.
[10] The GRID model is PacifiCorp's least cost dispatch model it uses to calculate NVPC.

and brought back on-line the following day. PacifiCorp has defined the difference in NVPC between these two runs as incremental O&M and indicated that these expenses are incurred on an actual basis.

Q. DO YOU AGREE WITH PACIFICORP THAT THIS MODELING CORRECTION WILL CAUSE THE FACILITY TO INCUR MORE MAINTENANCE COSTS ON AN ACTUAL BASIS THAN WHAT IS ALREADY INCLUDED IN RATES?

A. No. The modeling correction is simply that, a modeling correction. These costs are a duplication of the O&M costs already included in base rates. Because the Company uses actual O&M expenses, which includes all impacts from the cycling of these units, there is no justification for including additional O&M costs in the TAM filing.

<u>Long Hollow Facility</u>

Q. PLEASE PROVIDE A BACKGROUND ON THE "LONG HOLLOW' FACILITY.

A. In Staff Data Request No. 52, the Company clarified that the "Long Hollow" facility is actually called Pleasant Valley Wind Farm. Pleasant Valley Wind Farm has a total capacity of 144 MW, and is operated by NextEra and the power is purchased by Iberdola. The Company refers to the facility as Long Hollow because of the Long Hollow switching station at which the Company receives energy from the project.

Q. WHAT TYPE OF AN AGREEMENT DOES THE FACILITY HAVE WITH PACIFICORP?

A. PacifiCorp provides transmission service through an existing Transmission Service and Operating Agreement and a point-to-point agreement. The Company is also responsible for providing operating reserves and wind integration services.

Q. IS THE COMPANY CURRENTLY CHARGING AN ENTITY FOR THE WIND INTEGRATION SERVICES IT IS PROVIDING?

A. No. According to the Company, charging non-owned generators for the cost of wind integration would require modification of the Company's Open Access Transmission Tariff.[11] The Company has not applied to FERC to accomplish this modification.

Q. WHAT BENEFIT DOES THIS AGREEMENT PROVIDE TO PACIFICORP CUSTOMERS?

A. The only benefit this agreement provides is the revenue PacifiCorp realizes for providing transmission and operating reserves, which is booked into the "Other Revenue" account. The Company is currently not receiving revenue for wind integration services.

Q. PLEASE SUMMARIZE STAFFS RECOMMENDATION ASSOCIATED WITH THE PLEASANT VALLEY WIND FARM.

A. The Company should commit to modifying its tariff at FERC to include additional charges associated with providing wind integration services to non-

[11] See Exhibit Staff/103, Brown/10.

owned wind facilities. Alternatively, the Company should explain why this proposed modification is unwarranted.

Other Revenue

Q. PLEASE DISCUSS STAFF'S RECOMMENDATION ASSOCIATED WITH THE "OTHER REVENUE" ACCOUNT.

A. In non-general rate case years, in which only a power cost update is filed, the Company is allowed to include or update the costs associated with new resources, contracts and existing facilities for services that it is providing to a third party entity. With the update or inclusion of these new costs there can also be a corresponding change in revenue. If these revenues are accounted for as "other revenue" they currently go un-recognized in rates. This mismatch between updating costs and revenues is unreasonable.

Q PLEASE PROVIDE AN EXAMPLE OF THIS INEQUALITY.

A. For example, if the Company had not filed a General Rate Case (GRC) concurrently with its TAM filing this year all of the revenue the Company receives on behalf of the transmission agreement with the Pleasant Valley wind farm would not have been recognized. I use this example because it is a very clear case where the service provides no benefit to customers other than the recognition of revenue that the Company receives. There are many contracts and agreements of this nature in the existing TAM, e.g. storage and exchange agreements, steam sales, gas resale revenue, and other ancillary services. Staff believes that this regulatory asymmetry is inequitable to the customer and needs to be corrected in all TAM filings that are not filed concurrently with a GRC.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 207
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

July 14, 2009

WITNESS QUALIFICATION STATEMENT

NAME:	Kelcey Brown
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Electric and Natural Gas Division, Resource and Market Analysis
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	All course work towards Masters in Economics University of Wyoming B.S. University of Wyoming Major: Business Economics Minor: Finance

EXPERIENCE:

Since November 2007 I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric utilities. I have provided testimony in UE 199, UE 200, UE 204, and UM 1355 and have actively participated in regulatory proceedings in Oregon, including UE 195, UE 198, LC 47 and UM 1429.

From June 2003 to November 2007 I worked as the Economic Analyst for Blackfoot Telecommunications Group, a competitive and incumbent telephone provider in Missoula, Montana. I conducted all long and short term sales and revenue forecasts, resource acquisition cost-benefit analysis, business case analysis on new products and build-outs, pricing, regulatory support, market research, and strategic planning support.

From May 2002 to August 2002 I worked as an intern at the Illinois Commerce Commission in Springfield, Illinois. I performed competitive market analysis, spot market monitoring and pricing review, and extensive research on locational marginal pricing and transmission system incentives for development.

My course work, towards a Master's degree at the University of Wyoming, focused heavily on the regulatory economics of network industries such as electricity, natural gas, and telecommunications.

CASE: UE 207
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 102

Exhibits in Support of Reply Testimony

July 14, 2009

Hydro Adjustment Facility	MWh Change	Market Avg price	Total $'s	SG	Oregon $'s
Toketee	25,827	$63.75	$1,646,443	26.88%	$442,514
Bear Creek	130,333	$61.50	$8,015,480	26.88%	$2,154,320
JC Boyle	46,940	$63.75	$2,992,393	26.88%	$804,266
	203,099		$12,654,316	26.88%	$3,401,100
Condit	81,959	$63.75	$5,224,899	26.88%	$1,404,296
		Total	$17,879,215	26.88%	$4,805,396

Additional O&M Costs	SG	Oregon $'s
$2,100,498	26.88%	$564,551

PacifiCorp Data Unit	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total 2009*	Total 2010	Change 2010-2009	% Change 2010
Bear	8,846	10,080	20,667	17,513	19,275	19,131	26,249	21,826	9,010	4,711	7,200	7,509	302,352	172,018	-130,333	-43%
Bend	223	202	236	423	517	504	519	448	420	236	147	220	5,048	4,094	-954	-19%
Big Fork	1,567	1,682	1,527	1,675	2,124	2,077	2,539	2,183	1,515	1,511	1,673	1,680	27,467	21,763	-5,704	-21%
Chelan - Rocky Reach	33,684	24,357	23,972	29,847	33,505	34,820	33,200	25,159	17,390	20,396	23,035	26,351	327,298	325,718	-1,581	0%
Clearwater 1	2,851	2,871	3,566	3,154	3,331	3,340	2,724	2,552	2,208	2,319	2,474	2,856	39,913	34,245	-5,669	-14%
Clearwater 2	3,932	4,006	5,193	4,968	4,648	3,434	3,140	2,959	2,406	2,781	2,898	3,644	50,072	44,007	-6,064	-12%
Condit	-	-	-	-	-	-	-	-	-	-	-	-	73,152	-	-73,152	-100%
Copco 1	16,811	15,832	17,159	12,514	8,190	7,722	5,326	5,220	4,947	6,740	6,571	8,274	114,432	115,306	874	1%
Copco 2	21,806	19,734	21,444	15,724	10,426	9,501	6,552	6,457	6,151	8,408	8,108	10,551	140,427	144,862	4,435	3%
Douglas - Wells	26,087	18,603	18,065	23,297	28,016	27,301	26,469	19,586	13,085	15,393	17,432	20,042	254,198	253,377	-822	0%
Eagle Point	1,404	1,277	999	1,145	1,175	1,066	1,035	1,034	842	146	1,039	1,427	14,038	12,590	-1,449	-10%
East	6,889	5,333	8,037	11,351	15,619	14,530	13,251	12,163	9,117	6,687	4,705	6,672	140,017	114,352	-25,665	-18%
East Side	2,180	1,975	2,074	2,148	1,402	1,933	1,386	1,146	507	866	623	699	15,897	16,938	1,040	7%
Fall Creek	1,054	996	1,093	1,008	1,022	945	967	919	930	955	982	1,035	12,891	11,905	-986	-8%
Fish Creek	5,730	5,828	7,014	7,449	7,593	5,348	819	-	-	-	1,875	5,026	46,379	46,682	303	1%
Grant - Wanapum	-	-	-	-	-	-	-	-	-	-	-	-	593,402	-	-593,402	-100%
Grant Priest Rapids Development	5,122	3,781	3,684	3,379	2,499	3,197	3,643	3,316	2,677	3,135	3,554	4,068	49,233	42,054	-7,178	-15%
Grant Wanapum Development	4,699	3,368	3,270	4,139	5,011	4,997	4,592	3,182	2,350	2,761	3,163	3,631	22,522	45,162	22,641	101%
Iron Gate	13,472	12,490	13,837	13,451	12,272	11,227	7,440	7,217	7,065	9,828	9,602	9,859	125,479	127,758	2,279	2%
JCBoyle	59,059	54,044	59,975	38,451	20,855	25,066	10,819	13,687	10,504	14,451	17,618	23,207	394,677	347,737	-46,940	-12%
Lemolo 1	14,001	11,603	14,164	9,815	14,233	13,348	10,247	9,605	13,001	10,843	11,125	13,246	143,334	145,231	1,897	1%
Lemolo 2	15,198	12,622	15,814	12,290	15,110	15,272	11,519	9,793	12,873	10,175	11,390	14,178	171,751	156,234	-15,518	-9%
Merwin	85,333	68,345	72,108	49,006	35,609	28,538	17,939	20,894	27,468	20,116	50,219	78,131	534,661	553,706	19,045	4%
Powerdale	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
Prospect 1	2,892	2,614	2,892	2,796	2,965	2,783	2,556	670	750	181	1,435	2,760	28,822	25,295	-3,527	-12%
Prospect 2	19,292	19,643	22,146	21,714	22,803	20,217	15,561	12,135	9,518	9,087	10,101	14,356	233,704	196,573	-37,130	-16%
Prospect 3	3,196	3,568	4,251	4,300	4,491	4,177	2,993	1,900	1,082	940	1,299	2,322	39,902	34,519	-5,382	-13%
Prospect 4	557	488	536	521	578	517	477	134	152	38	276	542	5,766	4,816	-950	-16%
Slide Creek	9,124	8,039	10,110	9,767	10,729	8,524	5,824	4,895	5,714	5,063	6,134	8,299	88,063	92,222	4,159	5%
Soda Springs	6,093	5,509	5,808	6,495	4,230	2,828	3,756	2,843	3,052	2,809	3,478	5,220	56,406	52,121	-4,285	-8%
Swift 1	93,475	79,630	80,269	50,305	48,160	51,942	27,611	27,735	53,849	19,191	50,134	87,082	658,375	669,382	11,007	2%
Swift 2	34,795	30,277	31,365	18,584	16,824	17,348	9,164	9,504	20,093	7,410	18,662	31,887	222,520	245,913	23,393	11%
Toketee	18,499	16,920	20,952	19,873	22,961	19,750	14,425	12,088	13,206	11,796	13,605	17,322	227,223	201,396	-25,827	-11%
Wallowa Falls	160	221	272	255	389	447	361	236	307	258	255	305	5,062	3,466	-1,596	-32%
West Side	374	403	446	425	321	365	369	190	137	188	245	285	3,623	3,748	125	3%
Yale	82,132	70,912	72,529	49,000	39,256	36,296	20,045	22,625	38,739	19,369	50,142	78,605	591,964	579,649	-12,315	-2%
												Total	5,760,058	4,844,828	-915,230	-15.89%

*2009 Hydro totals were provided in the UE 199 GRID Model workpapers

CASE: UE 207
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 103

Exhibits in Support of Reply Testimony

July 14, 2009

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 103

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 09-113. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 207 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

UE-207/PacifiCorp
June 17, 2009
OPUC Data Request 59

OPUC Data Request 59

Please provide the forecast methodology for each hydro facility modeled in GRID. Please discuss this methodology and provide justification for any differences in methodology associated with each facility. Some examples of the types of forecasts are: rolling average of the entire historical time frame, weighted average of the historical time frame, etc... Please discuss if the Company has recently changed this methodology from that used in UE 199.

Response to OPUC Data Request 59

The Company has changed the methodology from that used in UE 199 in order to decrease potential modeling volatility and align with actual project operations. Listed below are the forecast assumptions for each hydro facility in GRID:

Bear River – Single year "hydrology" excludes flood control years and assumes extension of regional drought. Hydrology is actually historic generation.

Klamath River – Single year hydrology based on median volume.

Lewis River – Single year hydrology based on median volume. Smoothing factor applied to reduce variability.

Umpqua River – Single year hydrology based on median volume. Smoothing factor applied to reduce variability. Historic inflows were re-calculated before median calculation.

Mid Columbia – Single year hydrology based on median between 1929 and 1997.

Run of River – Single year "hydrology" is actually historic generation.

UE-207/PacifiCorp
June 17, 2009
OPUC Data Request 56

OPUC Data Request 56

In UE 199 PacifiCorp provided to Staff in data request No. 45-2 (confidential) an Excel spreadsheet which had a chart, summary, notes and assumptions on hydro modeling and conditions. Please provide this same information updated for the UE 207 filing.

Response to OPUC Data Request 56

Please refer to Confidential Attachment OPUC 56 which includes an updated version to the list of notes and assumptions on hydro modeling and conditions as well as a chart and summary for 30 year projected generation. Confidential information is provided subject to the terms and conditions of the protective order in this proceeding. The information was provided in UE 199 to support the adjustments made to the normalized hydro generation. The information is not used in the current docket due to updates in the inputs and methodology to prepare the normalized hydro generation.

Please refer to Confidential Attachment OPUC 56 on the enclosed CD.

Pages 3 through 7 are confidential.

You must have signed the protective order in this docket in order to view this page.

UE-207/PacifiCorp
June 17, 2009
OPUC Data Request 60

OPUC Data Request 60

In the net power cost report there is a 43 percent drop in hydro production from the Bear Hydro facility as compared to UE 199. Please discuss why the drop in production is so significant at this facility for test year 2010. Please provide the incremental impact to net variable power costs in UE 207 associated with the 43 percent drop in production from the Bear Hydro facility.

Response to OPUC Data Request 60

Flood control years have historically provided additional water for Bear River generation. However, the region is currently impacted by long term drought conditions and, based on water levels in Bear Lake, flood control years are not anticipated for the next three years. As a result, flood control years were not included in the single water year calculation for the next three years. Flood control years were added back into the forecast after three years.

The Vista model uses generation as the input for the Bear River. The single year forecast is based on the monthly median generation of the last 30 years, excluding flood control years.

The Company has not performed studies that isolate the impact of the drop in hydro production from the Bear River.

UE-207/PacifiCorp
June 18, 2009
OPUC Data Request 69

OPUC Data Request 69

a. Please provide the assumptions used by the Company in order to determine each item of "Additional Fixed Costs" included in the net power cost report.
b. Are these items based on an average of the past four years of actual information?
c. Where they determined using an assumption of an incremental cost per start?
d. What historical performance information did the Company use to determine the incremental level of Additional Fixed Costs for each unit, as they are run by GRID?
e. Please provide all work papers electronically with formula's and links intact.

Response to OPUC Data Request 69

Because the GRID model does not capture the startup costs of the gas-fired units that are not included in any other FERC accounts, a line item is added to the net power cost report to capture the startup fuel costs of the gas-fired units, together with the adjustments made for the O&M costs associated with the additional startups required to screen the gas-fired units.

a. All calculations and underlying assumptions relating to "Additional Fixed Costs" were provided with the TAM support workpapers, Set 2: "O1 - OR CY2010 Additional Startup Costs (Confidential).xls" and "O2 - OR CY2010 Startup Cost Source (Confidential).xls."

b. No.

c. Yes, see TAM support workpapers, Set 2: "O1 - OR CY2010 Additional Startup Costs (Confidential).xls" and "O2 - OR CY2010 Startup Cost Source (Confidential).xls."

d. Start up consumption of gas in GRID is determined by identifying the amount of gas required to bring a gas plant up to minimum load after being shut down. Start ups on gas plants can vary considerably. The gas consumption numbers will vary on the steam turbine temperature parameters as well as any other plant specific issues during the start. The startup consumption that the Company used is estimated based on the experience and observation of the operators.

   When gas turbines are cycled off line, the thermal cycling of the hot components has a significant detrimental effect upon the life of the components and hence the maintenance cost. General industry belief is that the approximate cost of this impact is around $10,000 - $12,000 per start depending upon the particular gas turbine manufacturer.

UE-207/PacifiCorp
June 15, 2009
OPUC Data Request 53

OPUC Data Request 53

Is PacifiCorp currently charging the Long Hollow wind facility owner a separate charge for wind integration services, similar to the storage and exchange agreements? If so, please provide the contract language associated with the separate wind integration charge realized by the Long Hollow wind facility. If there is no separate wind integration charge please discuss why the Company is not charging for wind integration services.

Response to OPUC Data Request 53

No. Charging non-owned generators for the cost of wind integration would require modification of the Company's Open Access Transmission Tariff (OATT). The Federal Energy Regulatory Commission has not authorized the Company to charge wind facilities a separate charge for wind integration services at this time.

CASE: UE 207
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Reply Testimony

July 14, 2009

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 200

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 09-113. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 207 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Michael Dougherty. I am the Program Manager for the Corporate Analysis and Water Regulation Section of the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to describe my adjustments to PacifiCorp's Coal Fuel Burn Expense as listed in Exhibit PPL (TAM)/103, Duvall/5.

Q. HAVE YOU PREPARED ANY EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared:

Exhibit Staff/202, consisting of 1 page;

Confidential Exhibit Staff/203, consisting of 5 pages;

Exhibit Staff/204, consisting of 29 pages; and

Confidential Exhibit Staff/205, consisting of 7 pages.

Q. PLEASE PROVIDE A SUMMARY OF YOUR ADJUSTMENTS.

A. The following table summarizes my adjustments to PacifiCorp's Coal Fuel Burn Expense as listed in Exhibit PPL (TAM)/103, Duvall/5.

Table 1 – Summary of Staff Adjustments

Plant	**Exhibit PPL(TAM)/103; Duvall/5**	**Staff**	**Adjustment**
Fuel Burn Expense (Third Party Contracts)			
Carbon	$19,446,056	$19,446,056	$0
Cholla	$54,964,906	$54,964,906	$0
Colstrip	$12,395,660	$12,395,660	$0
Dave Johnston	$52,590,391	$51,659,769	$930,622
Hayden	$11,369,342	$11,369,342	$0
Naughton	$80,290,581	$80,290,581	$0
Wyodak	$19,440,034	$19,440,034	$0
Subtotal	**$250,496,970**	**$249,566,348**	**$930,622**
Fuel Burn Expense (Third Party and Affiliated Interest Contracts)			
Craig	$20,691,191	$20,691,191	$0
Jim Bridger	$180,236,369	$162,428,259	$17,808,110
Huntington	$96,354,411	$95,146,344	$1,208,067
Hunter	$111,340,062	$111,340,062	$0
Subtotal	**$408,622,033**	**$389,605,856**	**$19,016,177**
Total Adjustment			**$19,946,799**
Total Oregon Adjustment Based on SG Factor			**$5,361,081**

Q. PLEASE SUMMARIZE THE ANALYSES SUPPORTING YOUR RECOMMENDED ADJUSTMENTS.

A. Dave Johnston plant – As a component of the Dave Johnston Fuel Burn Expense, PacifiCorp provides a forward market price of [redacted] per ton for "Unidentified Surface" (FOB Mine) coal. In my analysis, I compared this forward price with the Energy Information Administration's (EIA) July 2, 2009, Average Weekly Coal Commodity Spot Prices (Dollars per Short Ton) for the Powder River Basin (8,800 Btu) of $9.00 per ton. To determine a price for PacifiCorp's "Unidentified Surface," I used the EIA spot price and escalated this price based upon a PacifiCorp-provided escalation rate to receive a price per ton of [redacted]. Therefore, I am substituting the forward market price with an escalated spot price. The use of the escalated spot price for PacifiCorp's "Unidentified Surface" coal results in a $930,622 system-wide adjustment.

Jim Bridger and Huntington plants – Because both plants receive coal from affiliated interest mines, I performed lower of cost or market analyses pursuant to Oregon Administrative Rule (OAR) 860-027-0048, *Allocation of Costs by an Energy Utility*. The lower of cost or market analyses result in Jim Bridger and Huntington adjustments of $17,808,110 and $1,208,067, respectively.

Q. DO YOU PROVIDE ALTERNATE RECOMMENDATIONS FOR THE COMMISSION TO CONSIDER?

A. Yes. Concerning coal costs from affiliate, Bridger Coal Company (BCC), I performed four primary lower of cost or market analyses.[1] My primary analysis, as shown in the above table, results in a system-wide adjustment of $17,808,110 for Jim Bridger (Bridger) Fuel Burn Expense. A secondary alternate analysis results in a system-wide adjustment of $17,224,031 for Bridger Fuel Burn Expense. A third alternate analysis results in a system-wide adjustment of $11,034,328 of Bridger Fuel Burn Expense. I also performed a fourth analysis that I did not use as a recommended adjustment. These analyses are explained later in testimony and are shown in Staff Confidential Exhibit/203, Dougherty/2. The following table shows the total Oregon Coal Fuel Burn Expense adjustment based on three lower of cost or market analyses concerning BCC.

Table 2 – Alternate Recommended Oregon Adjustments

Primary Adjustment	$5,361,081
First Alternate Adjustment	$5,204,099
Second Alternate Adjustment	$3,540,499

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

[1] In addition to the four lower of cost or market analyses demonstrated, I performed two additional analyses for comparative purposes. These are described later in testimony.

ISSUE 1, ADJUSTMENT TO DAVE JOHNSTON FUEL BURN EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DAVE JOHNSTON.

A. Dave Johnston receives coal from certain third party mines. In addition, PacifiCorp has set aside and priced a certain amount of coal that the Company labels as "Unidentified Surface." PacifiCorp, in its response to Staff Data Request No. 50,[2] states that the cost represents the forward market price, FOB Mine of PRB 8,400 Btu coal. In my adjustment, I substituted the forward market price of the unidentified surface coal with the Energy Information Administration (EIA) Average Weekly Coal Commodity Spot Price (Dollars per Short Ton) for the Powder River Basin (8,800 Btu)[3] as of July 2, 2009, price of $9.00, which I escalated based on certain information PacifiCorp provided. According to the EIA Average Weekly Coal Commodity Spot Prices,[4] the previous price of $8.75 held steady from April 10, 2009, to June 26, 2009.

[redacted][5]

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[2] Included in Exhibit Staff/204.

[3] During Staff's *2008 Audit of PacifiCorp, Audit 2008-002* (page 47), PacifiCorp reported that the heat content of coal used by the Dave Johnston plant ranged from 8,000 – 8,800 Btu/lb. As a result, there is no mismatch concerning heat content between the market price coal and coal that is used in the Dave Johnston plant. The applicable page is included in Exhibit Staff/204.

[4] EIA Average Weekly Coal Commodity Spot Prices, http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html#spot

[5] PacifiCorp's response to Staff Data Request No. 36a explains the indexing PacifiCorp used for indexed contracts and is included in Exhibit Staff 204.

[redacted][6] [redacted] It is important to note that I am using an escalated spot price while the Company is using a forward market price to determine the cost of the "Unidentified Surface" coal. As an indicator of cost trends, the EIA states that the average delivered coal price is expected to decline to $1.98 per MMBtu in 2010 (from $2.16 MMBtu in 2009), as expiring high-priced contracts are replaced.[7] I did not make any adjustments to transportation costs concerning the "Unidentified Surface" coal. The total adjustment to the Dave Johnston Coal Fuel Burn Expense is $930,622 system-wide; $250,122 for Oregon.[8] The resulting Dave Johnston Fuel Burn Expense is shown on Confidential Exhibit Staff/203, Dougherty/1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY CONCERNING THE DAVE JOHNSTON FUEL BURN EXPENSE?

A. Yes.

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[6] Included in Confidential Exhibit Staff/205.

[7] EIA Short-term Energy Outlook, http://www.eia.doe.gov/steo, June 9, 2009, Release. Included in Exhibit Staff/204.

[8] The Oregon allocation factor assumed in this value will likely change, as will the adjustment, to conform to staff's recommendations in UE 210, the docket investigating PacifiCorp's general rate filing.

ISSUE 2, ADJUSTMENTS TO FUEL BURN EXPENSES RESULTING FROM AFFILIATED INTEREST COAL MINES

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS CONCERNING AFFILIATED INTEREST MINES.

A. Concerning the Fuel Burn Expense of plants that receive coal from affiliated interest mines, I performed lower of cost or market analyses pursuant to OAR 860-027-0048, *Allocation of Costs by an Energy Utility*. The two adjustments that I recommend concern the Jim Bridger and Huntington plants that are $17,808,110 and $1,208,067, respectively.

Q. DOES THE COMMISSION HAVE A TRANSFER PRICING POLICY CONCERNING TRANSACTIONS BETWEEN A UTILITY AND ITS AFFILIATED INTERESTS?

A. Yes. OAR 860-027-0048, *Allocation of Costs by an Energy Utility*, affirms the Commission's Transfer Pricing Policy. Section (4)(e) of the rule states:

> When services or supplies (except for generation) are sold to an energy utility by an affiliate, sales shall be recorded in the energy utility's accounts at the approved rate if an applicable rate is on file with the Commission or with FERC. If services or supplies (except for generation) are not sold pursuant to an approved rate, sales shall be recorded in the energy utility's accounts at the affiliate's cost or the market rate, whichever is lower.

As the rule states, supplies that are not under an approved rate shall be recorded in the energy utility's accounts at the lower of the affiliate's cost or market rate. Bridger Coal Company (BCC), Deer Creek Mine (which supplies coal to the Hunter and Huntington plants), and Trapper Mining (which supplies coal to the Craig plant) are affiliates of PacifiCorp. As a result, this transfer pricing is relevant concerning pricing of coal supplied from these affiliated interest mines.

Q. PLEASE EXPLAIN THE AFFILIATED RELATIONSHIP BETWEEN PACIFICORP AND BRIDGER COAL COMPANY.

A. According to PacifiCorp's 2008 Affiliated Interest Report, Pacific Minerals, Inc. (PMI) is a wholly owned subsidiary of PacifiCorp. PMI owns 66.67 percent of BCC, the coal mining joint venture with Idaho Energy Resources Company (IERC),[9] which is a subsidiary of Idaho Power Company. The Commission approved a coal supply agreement between BCC and PacifiCorp in Commission Order No. 01-472 (UI 189), dated June 12, 2001.

Q DID COMMISSION ORDER NO. 01-472 (UI 189) REQUIRE A REVIEW OF THE LOWER OF COST OR MARKET STANDARD CONCERNING PRICING OF COAL FROM BCC?

A. Yes. In its public meeting memo, Staff stated:

> Staff believes that the appropriate standard the Commission has used and continues to use for ratemaking is its affiliate interest transfer pricing requirements, namely that the price is the lower of cost or fair market rate.[10]

Staff concluded that at the time of the affiliated interest application, BCC's costs were lower than market and stated:

> The Commission's transfer policy for goods and services purchased by a regulated electric utility from an affiliate shall be priced at the lower of cost or fair market rate. This policy likely has been met because BCC is charging PacifiCorp a price for its coal supply based on BCC's fully distributed cost that is currently less than the market rate. The company's rate of

[9] IERC owns the remaining 33.33 percent of Bridger Coal Company.
[10] Commission Order No. 01-472 (UI 189), Appendix A, page 2. *See* Exhibit Staff 204.

> return used in billing from BCC to PacifiCorp is at the same rate authorized by the Commission in PacifiCorp's most recent rate case. This is consistent with the Commission's affiliated interest (AI) transfer pricing policy. Proposed ordering condition No. 4 is included to ensure that PacifiCorp adheres to the Commission's policy.[11]

In addition to condition No. 4, Staff's public meeting memo also included the following conditions No. 2 and No. 3:

> 2. The Commission reserves the right to review for reasonableness all financial aspects of this arrangement in any rate proceeding or alternative form of regulation.
>
> 3. PacifiCorp shall notify the Commission in advance of any substantive changes to the agreement, including any material changes in any cost. Any changes to the terms which alter the intent and extent of activities under the agreement from those approved herein shall be submitted in an application for a supplemental order (or other appropriate format) in this docket.[12]

Q. BASED ON YOUR REVIEW HAS THERE BEEN A MATERIAL CHANGE IN PRICE OF BCC COAL?

A. Yes. Staff's UI 189 memo includes the following information:

> The company states that BCC coal provides it with advantages such as a consistently reliable coal source and a minimization of fuel transportation and handling costs. Historically, from 1990 through 1999, the average cost of coal provided by the Coal Supply Agreement ranged from $3 to $9 per ton less than the average market price of Southern Wyoming coal delivered to the plant.[13]

However, after calculating four lower of cost or market analyses, my review indicates that BCC's costs are no longer below market costs for the Green

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[11] Commission Order No. 01-472 (UI 189), Appendix A, pages 2 and 3. *See* Exhibit Staff 204.
[12] *Ibid*, Appendix A, page 4. *See* Exhibit Staff 204.
[13] *Ibid*, Appendix A, page 2. *See* Exhibit Staff 204.

River Basin (GRB) in Southern Wyoming. Therefore, there is a substantial change in costs.

Q. BECAUSE PPL (TAM)/200, LASICH/6 STATES THAT THERE IS NO ADDITIONAL (COAL) CAPACITY IN THE AREA TO SUPPLY THE BRIDGER PLANT, SHOULD THE COMMISSION STILL CONSIDER USING THE TRANSFER PRICING POLICY CONCERNING BCC?

A. Yes. OAR 860-027-0048 applies to pricing and a market. Based on information provided by PacifiCorp in confidential responses to Staff's Data Requests Nos. 5, 6, and 36,[14] there is a market and pricing for coal in the GRB. PacifiCorp uses this market provided coal for both the Jim Bridger and Naughton plants. Therefore, the Commission should use the lower of cost or market standard pursuant to OAR 860-027-0048.

Q. PLEASE DISCUSS BCC'S OPERATIONS AND COSTS.

A. BCC's overall costs are a weighted cost of surface mining operations, underground mining operations, and incremental coal costs. The following table highlights the percentage of coal mined, the cost per ton of coal produced per operation, and the weighted cost. This calculation is also shown in Confidential Exhibit Staff/203, Dougherty/2.

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[14] Included in Confidential Exhibit Staff/205.

Table 3 – BCC's Weighted Cost per Ton

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Q. HAS PACIFICORP DISCUSSED COST DRIVERS CONCERNING BCC COAL?

A. Yes. PacifiCorp explains certain changes in BCC's costs in PPL (TAM)/200, Lasich/4 and 5 by stating:

> For many years, BCC was able to extract coal at the Bridger surface mine using low-cost highwall mining. The mine has now reached the stage, however, where BCC has replaced this production method with higher-cost dragline mining to properly steward the resources of the mine. Additionally, current accounting pronouncement EITF04-6 requires that production costs be assigned only to extracted coal, not coal that is uncovered but remains in the pit. This contributes to higher costs in 2010 because more coal is scheduled to be uncovered than will be extracted; the opposite will be true in a year when previously uncovered coal is ultimately extracted.

As can be seen from the above statement, one of the cost drivers is an accounting treatment concerning extracted coal that PacifiCorp (and other mines) must comply with. PacifiCorp's response to Staff Data Request No. 51[15] states that without EITF 04-6, 2010 test period cost of BCC would be $30.63 per ton as compared to $33.54 per ton with EITF 04-6.

Based on information, supplied in its confidential response to Staff Data Request No. 5, PacifiCorp provided cost data demonstrating that BCC [redacted] which comprises approximately [redacted] percent of BCC's mining operations. It should be noted that PacifiCorp's inputs the [redacted] per ton cost to determine the Fuel Burn Expense for the Bridger plant. To further illustrate the effect of the 2010 increase in [redacted] Confidential Exhibit Staff/203, Dougherty/3 demonstrates the BCC weighted costs replacing the [redacted]

Q. PLEASE EXPLAIN YOUR LOWER OF COST OR MARKET ANALYSIS.

A. Because I had concerns with the level of certain cost components embedded in the weighted costs, I performed four analyses, which substituted certain pricing in the BCC weighted costs with market costs that were provided by PacifiCorp in confidential responses to Staff Data Requests No. 5 and No. 36. In order to

[15] Included in Exhibit Staff/204.

examine market prices for the GRB area of Wyoming, I examined PacifiCorp's third party contracts that supply coal to the Bridger and Naughton coal plants, both of which are located in the GRB. Pursuant to PacifiCorp's confidential response to Staff Data Request No. 6, Black Butte Mine will provide [redacted] thousand tons of coal (PacifiCorp's share) to the Bridger coal plant in 2010 at a total cost (coal and transportation) of [redacted] per ton. This coal accounts for approximately 33 percent of the coal burned by Bridger. The mine supplying Naughton (Naughton mine) will provide [redacted] thousand tons of coal at a total price of [redacted] per ton.[16] Based on information supplied by PacifiCorp, the Naughton-supplied mine accounts for 100 percent of the coal burned by the Naughton coal plant. Both Black Butte and Naughton mines [redacted]

Because these coal sources are located in the GRB, I used both sources in my market cost analysis. Additionally, in my primary market analysis, I used BCC's underground operations and BCC's incremental costs[17] as a component of market costs. I used the underground mining operations because it is an essential part of BCC's operations. The following table highlights my primary recommendation concerning lower of cost or market pricing. This calculation is also shown in Confidential Exhibit Staff/203, Dougherty/2.

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16 [redacted]

17 According to PacifiCorp's response to Staff Data Request No. 38, signifies a spot coal supply for the Bridger plant.

Table 4 – Primary Market Analysis – Bridger Coal Costs

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted] As a result, the calculated [redacted] coal cost per ton represents a market cost that considers both underground and surface mining operations; and uses two market sources. As a result of using a lower cost per ton, I calculated a $17,808,110 (system-wide) adjustment to Bridger Fuel Burn Expense as highlighted in the following table. This calculation is also shown in Confidential Exhibit Staff/203, Dougherty/2.

Table 5 – Recommended Bridger Fuel Burn Expense

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Using PacifiCorp's allocation for steam generation (26.8769 percent), the Oregon allocated adjustment is $4,786,268.[18]

Q. PLEASE SUMMARIZE WHY YOU BELIEVE YOUR PRIMARY RECOMMENDATION SHOULD BE ACCEPTED BY THE COMMISSION.

A. I believe my primary recommendation should be accepted by the Commission because:

1. The transfer pricing policy pursuant to OAR 860-027-0048 applies to coal supplied by BCC to the Jim Bridger plant since there is a market and pricing is available;

2. The recommendation uses two sources of market costs (Black Butte and Naughton mines); and

3. The recommendation uses BCC's underground costs in order to recognize an underground component of weighted costs.

Q. PLEASE EXPLAIN YOUR SECONDARY MARKET ANALYSIS.

A. [redacted]. The [redacted] is a higher cost per ton than the [redacted] cost per ton calculated in the primary market analysis. As a result of this higher cost per ton, this first alternate recommended Bridger Fuel Burn Expense adjustment of

[18] See footnote 8.

$17,224,031 is lower than the primary recommended adjustment. The following table highlights the Bridger Fuel Burn Expense using the BCC [redacted]. This calculation is also shown in Confidential Exhibit Staff/203, Dougherty/2.

Table 6 – Second Market Analysis - Bridger Fuel Burn Expense

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Using PacifiCorp's allocation for steam generation (26.8769 percent), the Oregon allocated adjustment is $4,629,286.[19] It is important to note that PacifiCorp in its response to Staff Data Request No. 37[20] states that:

> The test period reflects the full capacity of the underground operations in 2010 – 4,633,943 tons of underground coal will be delivered to the Bridger Plant. The Bridger underground mine produced a high of 509,481 tons in August 2008; however, this tonnage level is not representative of an annual rate due to longwall moves and longwall panel development.

As such, [redacted] however, the cost should be considered in context of transfer pricing due to the [redacted]

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[19] See Footnote 8.
[20] Included in Exhibit Staff/204.

Q. PLEASE EXPLAIN YOUR THIRD MARKET ANALYSIS.

A. My third market analysis replaces [redacted] with the price of coal transported from the Powder River Basin (PRB) as discussed by PacifiCorp in PPL (TAM)/Lasich/6. PacifiCorp witness Mr. Lasich explains the analysis of the costs involved in transporting coal from the PRB and states:

> Based on the latest Union Pacific rail transportation proposal, the delivered cost of PRB coal is over $5/ton higher than coal from the Bridger Mine in the test period. Thus, coal from the Bridger Mine remains below the costs of any market alternative to the Company.

In addition to Mr. Lasich's testimony, PacifiCorp's confidential response to Staff Data Request No. 21,[21] provided the analysis of the $5 per ton higher costs. Although Staff does not disagree with the analysis, [redacted] The following table highlights my second alternate recommendation concerning lower of cost or market pricing. This calculation replaces [redacted] with the cost calculated by PacifiCorp to ship coal from the PRB region. This calculation is also shown in Confidential Exhibit Staff/203, Dougherty/2.

[21] Included in Confidential Exhibit Staff/205.

Table 7 – Third Market Analysis – Bridger Coal Costs

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The [redacted] cost per ton is a higher cost per ton than the [redacted] cost per ton calculated in the primary market analysis and the [redacted] cost per ton calculated in my secondary market analysis.[22] As a result of this higher cost per ton, the second alternate recommended Bridger Fuel Burn Expense adjustment of $11,034,328 is lower than the primary and first alternate recommended adjustments. The following table highlights the Bridger Fuel Burn Expense using the PRB coal as a replacement for [redacted] This calculation is also shown in Confidential Exhibit Staff/203, Dougherty/2.

Table 8 – Third Market Analysis - Bridger Fuel Burn Expense

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

22 [redacted] See Confidential Exhibit Staff/203, Dougherty/3.

Using PacifiCorp's allocation for steam generation (26.8769 percent), the Oregon allocated adjustment is $2,965,685.[23]

Q. YOU PREVIOUSLY MENTIONED THAT YOU PERFORMED A FOURTH MARKET ANALYSIS THAT YOU DID NOT USE, PLEASE EXPLAIN THIS ANALYSIS.

A. In my fourth market analysis, I averaged the Black Butte mine and Naughton mine coal tons and costs to determine a lower of cost or market pricing. As previously mentioned, both Black Butte and Naughton mines are [redacted] and this analysis does not include an underground component. The [redacted] per ton is a lower cost per ton than the [redacted] per ton calculated in the primary market analysis, lower than the [redacted] per ton calculated in the secondary market analysis, and lower than the [redacted] per ton calculated in the third market analysis. As a result of this lower cost per ton, this analysis would result in a $20,619,714 system-wide adjustment to PacifiCorp's Bridger Fuel Burn Expense. The following table highlights the Bridger Fuel Burn Expense using third party coal. This calculation is also shown in Confidential Exhibit Staff/203, Dougherty/2.

Table 9 – Fourth Market Analysis - Bridger Fuel Burn Expense

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[23] See footnote 8.

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

As previously mentioned, this analysis does not include an underground component. As a result, I did not include this lower cost or market analysis as a recommended cost concerning Jim Bridger Fuel Burn Expense.

It is important to note that, although I demonstrated four lower of cost or market analyses, as a result of the many different variables available, including 2008 and 2009 BCC coal costs per ton, additional lower of cost or market analyses could have been performed.

Q. DID YOU PERFORM LOWER OF COST OR MARKET ANALYSES FOR THE COAL PLANTS SUPPLIED BY DEER CREEK MINE?

A. Yes. I examined affiliated interest and third party mines costs supplying the Huntington, Carbon, and Hunter coal plants, which are located in Utah. In addition to receiving coal from a third party coal mines, the Huntington and Hunter coal plants also receive coal from Deer Creek Mine. Deer Creek Mine, located in Utah, is held by Energy West Mining Company.

Energy West Mining is a wholly owned subsidiary of PacifiCorp that provides mine-related services in the production of coal at the PacifiCorp-owned mines in Emery County, Utah. The Commission approved a mining service contract between PacifiCorp and Energy West in Commission Order 91-513 (UI 105), dated April 12, 1991.

Q DID COMMISSION ORDER NO. 91-513 (UI 105) INCLUDE A REVIEW OF THE LOWER OF COST OR MARKET STANDARD CONCERNING PRICING OF COAL FROM ENERGY WEST MINING?

A. Yes. The order states on pages 3 and 4:

> This cost-based approach and the limitation of EWMC's activities to those arising under the contract minimize the likelihood of cross-subsidization. Due to recent reductions in operating costs at EWMC's Utah mines, Pacific is purchasing coal at below market prices.[24]

The order also included the following condition:

> 4. The Commission reserves the right to review for reasonableness all financial aspects in any subsequent rate proceeding or alternative form of regulation.[25]

Q. PLEASE PROVIDE DETAILS ON YOUR LOWER OF COST OR MARKET ANALYSIS PERFORMED ON THE HUNTINGTON PLANT.

A. As previously mentioned, the Huntington plant receives coal from both third party coal and affiliated interest mines. Concerning Huntington, the Deer Creek coal cost including transportation is [redacted] per ton. In my lower of cost or market analysis, I used the average costs of third party providers providing coal to the Huntington, Hunter, and Carbon plants (from PacifiCorp's confidential responses to Staff Data Requests 5 and 36) to determine the market price of coal being supplied to the Huntington coal plant. The resulting average price was [redacted] per ton. This calculation is also shown in Confidential Exhibit Staff/203, Dougherty/4. All coal costs include transportation costs.

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[24] Commission Order No. 91-513 (UI 105). See Exhibit Staff 204.
[25] *Ibid.*

The calculated market cost of [redacted] per ton is lower than the Deer Creek coal cost of [redacted] per ton. As a result of using a lower cost per ton, I received a $1,208,067 system-wide adjustment to Huntington Fuel Burn Expense as highlighted in the following table. This calculation is also shown in Confidential Exhibit Staff/203, Dougherty/4.

Table 10 – Huntington Fuel Burn Expense Adjustment

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Using PacifiCorp's allocation for steam generation (26.8769 percent), the Oregon allocated adjustment is $324,691.[26]

Confidential Exhibit Staff/203, Dougherty/4 also shows an alternate analysis that uses the price of third party coal supplied to Huntington. The alternate analysis results in a system-wide adjustment of $3,388,538 ($910,734 – Oregon). I did not use this analysis because as previously described in testimony; I used an average cost of Black Butte and Naughton mine coal costs for determining Bridger market price. As a result, both recommended analyses use average regional third party costs.

[26] See footnote 8.

Q. PLEASE EXPLAIN WHY YOU DO NOT HAVE ADJUSTMENTS TO THE CARBON AND HUNTER COAL PLANTS WHICH ARE ALSO SUPPLIED BY DEER CREEK MINE.

A. According to PacifiCorp's response to Staff Data Request No. 31, all Deer Creek coal, which is mined through underground operations, is initially delivered to the Huntington Plant prior to delivery to the Carbon and Hunter coal plants. Additionally, as stated in the response to Staff Data Request No. 31,[27] PacifiCorp's 2010 Regulatory Fuel Budget does not reflect any transfers to the Carbon plant. As such, the Carbon coal plant is projected to receive all of the coal needed for operations for 2010 from third party providers and no lower of cost or market analysis was required for coal costs at the Carbon coal plant. As Table 1 indicates, I did not make an adjustment to Carbon coal costs.

Because transfer of coal to Hunter does not occur at an equal pro-rata basis throughout the year,[28] the Deer Creek coal delivered to Hunter was actually lower than the third party coal supplied to the Hunter plant. As a result, no additional lower of cost or market analysis was required for the Hunter coal plant. As Table 1 indicates, I did not make an adjustment to Hunter coal costs.

Q. PLEASE EXPLAIN YOUR LOWER OF COST OR MARKET ANALYSIS FOR THE CRAIG COAL PLANT THAT IS SUPPLIED BY TRAPPER MINING.

[27] Included in Exhibit Staff/204.
[28] PacifiCorp's response to Staff Data Request No. 31. Included in Exhibit Staff/204.

A. PacifiCorp holds a 21.4 percent interest in the Trapper Coal Mine, which supplies fuel to the Craig Power Plant, located in Colorado. The Commission approved a mining service contract between PacifiCorp and Trapper Mining in Commission Order 94-1550 (UI 140), dated July 25, 1994.[29] Based on information provided in PacifiCorp's confidential response to Staff Data Request No. 5, coal delivered to the Craig plant by Trapper Mining was actually lower than the third party coal supplied to Craig. As a result, no additional lower of cost or market analysis was required for Trapper Mining coal supplied to the Craig coal plant. As Table 1 indicates, I did not make an adjustment to Craig coal costs.

Q. DID YOU REVIEW SPECIFIC LINE ITEM COSTS FOR BCC AND DEER CREEK MINES?

A. As part of my review, I reviewed 2008 line item costs concerning BCC and Deer Creek Mine. This review resulted in the identification of costs (management overtime, certain bonus amounts, donations, etc.) that staff would recommend as adjustments for the parent company (PacifiCorp) during a general rate case review. However, as a result of the lower of cost or market analysis, I did not make these adjustments, as the lower of cost or market analysis resulted in greater adjustments to both Bridger and Huntington costs. Because I did not use these line item adjustments for both Bridger and Huntington, I did not make any line item adjustments to the Hunter plant in

[29] Included in Exhibit Staff/204.

order to be consistent in methodology. Confidential Exhibit Staff/203, Dougherty/5 shows the identification of certain costs.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS TO PACIFICORP'S COAL FUEL BURN EXPENSE.

A. The following table summarizes my recommended adjustments to PacifiCorp's Coal Fuel Burn Expense.

Table 11 – Summary of Staff's Recommended Adjustments

Recommendation	System	Oregon	Explanation
Recommended Adjustment	$19,946,799	$5,361,081	BCC Market – Uses certain BCC operations and average 3rd party coal costs supplied to Naughton and Jim Bridger coal plants. Huntington Market - Based on average Carbon, Hunter, and Huntington 3rd party coal costs. Dave Johnston adjustment.
Recommended Alternate	$19,362,719	$5,204,099	BCC Market - Alternate Calculation based on certain BCC operations. Huntington Market - Based on average Carbon, Hunter, and Huntington 3rd party coal costs. Dave Johnston adjustment.
Recommended Second Alternate	$13,173,017	$3,540,499	Uses PRB coal price replacing certain BCC operations. Huntington Market - Based on average Carbon, Hunter, and Huntington 3rd party coal costs. Dave Johnston adjustment.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 207
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

July 14, 2009

WITNESS QUALIFICATION STATEMENT

NAME:	MICHAEL DOUGHERTY
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	PROGRAM MANAGER, CORPORATE ANALYSIS AND WATER REGULATION
ADDRESS:	550 CAPITOL ST. NE, SALEM, OR 97308-2148
EDUCATION:	Master of Science, Transportation Management, Naval Postgraduate School, Monterey CA (1987) Bachelor of Science, Biology and Physical Anthropology, City College of New York (1980)
EXPERIENCE:	Employed with the Oregon Public Utility Commission from June 2002 to present, currently serving as the Program Manager, Corporate Analysis and Water Regulation. Also serve as Lead Auditor for the Commission's Audit Program. Performed a five-month job rotation as Deputy Director, Department of Geology and Mineral Industries, March through August 2004. Employed by the Oregon Employment Department as Manager - Budget, Communications, and Public Affairs from September 2000 to June 2002. Employed by Sony Disc Manufacturing, Springfield, Oregon, as Manager - Manufacturing, Manager - Quality Assurance, and Supervisor - Mastering and Manufacturing from April 1995 to September 2000. Retired as a Lieutenant Commander, United States Navy. Qualified naval engineer. Member, National Association of Regulatory Commissioners Staff Sub-Committee on Accounting and Finance.

CASE: UE 207
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 202

Exhibits in Support of Reply Testimony

July 14, 2009

UE 207 - Coal Fuel Burn Expense Adjustments

	Exhibit PPL(TAM)/103; Duvall/5	Staff Primary Recommendation Amount	Staff Primary Adjustment	Staff First Alternate Recommendation Amount	Staff First Alternate Adjustment	Staff Second Alternate Recommendation Amount	Staff Second Alternate Adjustment
Carbon	19,446,056	19,446,056	-	19,446,056	-	19,446,056	-
Cholla	54,964,906	54,964,906	-	54,964,906	-	54,964,906	-
Colstrip	12,395,660	12,395,660	-	12,395,660	-	12,395,660	-
Craig	20,691,191	20,691,191	-	20,691,191	-	20,691,191	-
Dave Johnston	52,590,391	51,659,769	930,622	51,659,769	930,622	51,659,769	930,622
Hayden	11,369,342	11,369,342	-	11,369,342	-	11,369,342	-
Hunter	111,340,062	111,340,062	-	111,340,062	-	111,340,062	-
Huntington	96,354,411	95,146,344	1,208,067	95,146,344	1,208,067	95,146,344	1,208,067
Jim Bridger	180,236,369	162,428,259	17,808,110	163,012,338	17,224,031	169,202,041	11,034,328
Naughton	80,290,581	80,290,581	-	80,290,581	-	80,290,581	-
Wyodak	19,440,034	19,440,034	-	19,440,034	-	19,440,034	-
Total	**659,119,003**	**639,172,204**	**19,946,799**	**639,756,284**	**19,362,719**	**645,945,986**	**13,173,017**

Recommended Adjustment	**19,946,799**	5,361,081	Oregon	Bridger Market - Uses certain BCC operations and average 3rd party coal costs. Huntington Market - Based on Carbon, Hunter, and Huntington 3rd party costs.
Recommended First Alternate	**19,362,719**	5,204,099	Oregon	Bridger Market - Alternate Calculation based on Bridger Underground Mine Cost. Huntington Market - Based on Carbon, Hunter, and Huntington 3rd party costs.
Recommended Second Alternate	**13,173,017**	3,540,499	Oregon	Uses PRB coal price replacing certain BCC operations. ($11,366,892 adjustment) Huntington Market - Based on Carbon, Hunter, and Huntington 3rd party costs.

Bridger and Huntington costs were based on lower of cost or market.

Dave Johnston replaces PPL forward price with escalated spot price.

Net of Plant Adjustments - Third Party	930,622	
	250,122	Oregon

CASE: UE 207
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support of
Reply Testimony

July 14, 2009

STAFF EXHIBIT 203

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 09-113. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 207 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 207
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support of
Reply Testimony

July 14, 2009

OPUC Data Request 50

As a follow-up to PacifiCorp's response to Staff Data Request No. 5, please explain the pricing for Dave Johnston "Unidentified Surface."

a. What is the basis of this pricing?
b. How does the pricing compare to Powder River Basin market costs?

Response to OPUC Data Request 50

The "unidentified surface" price is applied to the coal volumes that are above and beyond the actual contractual commitments for 2010 that were in place at the time the GRID study was prepared.

a. The coal price represents the forward market price, F.OB. Mine, of Powder River Basin 8400 btu coal.

b. See above.

The DOE/EIA prices exclude silt, culm, refuse bank, slurry dam, and dredge operations. The DOE/EIA did not include a price for underground operations in Wyoming (withheld to avoid disclosure), but the average 2007 market price for underground operations in Utah was listed at $25.69 and the average 2007 market price for total operations in Colorado was listed as $24.91.

The market prices in these neighboring states are comparable to PacifiCorp's 2007 costs for underground and combined operations (Bridger - $23.59; and Deer Creek - $26.27). The 2008 Deer Creek cost of $25.08 reflects a $1.19/ton decrease in cost from the 2007 level resulting in considerably lower than market levels ($28.41) in 2008. As noted by FERC Market Snapshot Regional Coal Spot Prices, Utah and Colorado coal prices have risen sharply in 2008.

In a response to a Staff data request, PacifiCorp stated that all power plants are typically designed and constructed to consume a typical range of coals. As an example, the Hayden Plant consumes Colorado coals, which are normally bituminous, while other plants (Jim Bridger, Dave Johnston, Wyodak, and Colstrip) consume sub-bituminous coals. The following table highlights the Btu/lb of coal used by PacifiCorp plants

Table 27 – Heat Content of Coals used by PacifiCorp Plants

Mines	Btu/lb
Hayden (Colorado)	10,500 – 11,300 Btu/lb
Dave Johnston, Wyodak and Colstrip (PRB)	8,000 – 8,800 Btu/lb
Jim Bridger (Green River Basin – Wyoming)	9,200 – 10,000 Btu/lb

According to its website, the DOE/EIA lists Powder River Basin (PRB) spot cost per short ton, as of November 7, 2008, as $14.50. The website does not distinguish between underground and surface operations as there appears to be a lack of historical pricing for Wyoming underground operations. (Bridger is currently the only underground mine operation in Wyoming.) However, it should also be noted that the cost of PRB coal is expected to increase due to rising costs of Appalachian coal. According to Mineweb.com[9]:

> Soaring demand for coal and spiking prices should open new markets at home -- and to a lesser extent overseas -- for low-cost, low-sulfur coal from Wyoming's Powder River Basin, providing a boost for the miners that produce it and the railroads that move it.

The article also points out:

[9] http://www.mineweb.com/mineweb/view/mineweb/en/page38?oid=54526&sn=Detail

Energy Information Administration
Official Energy Statistics from the U.S. Government

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Home > Coal > Coal News and Markets

Coal News and Markets

Report Released: July 06, 2009
Next Release Date: July 13, 2009

Average Weekly Coal Commodity Spot Prices

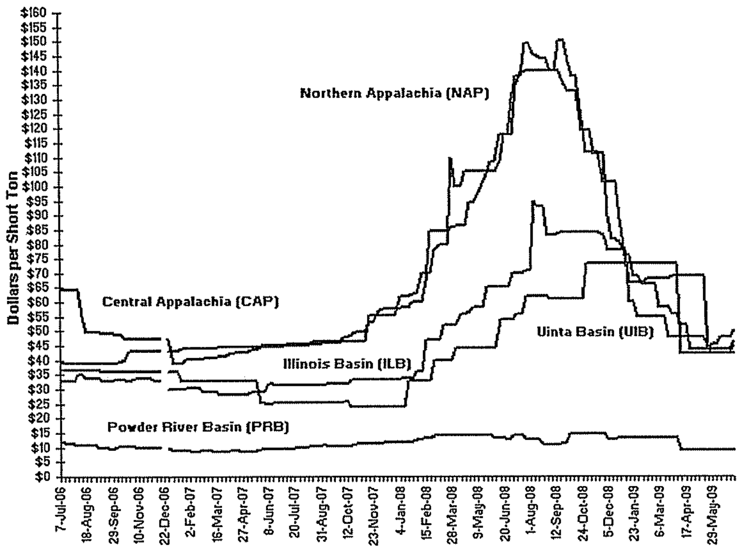
U.S. Monthly Coal Production

U.S. Eastern Coal Production

Electric Power Sector Coal Stocks

Average Cost of Metallurgical Coal Priced at Coke Plants

Historical Average Weekly Coal Commodity Spot Prices
(Dollars per Short Ton)
Business Week Ended July 02, 2009



Key to Coal Commodities by Region[1]

Central Appalachia:	Big Sandy/Kanawha 12,500 Btu, 1.2 lbSO2/mmBtu	Powder River Basin:	8,800 Btu, 0.8 lb SO2/mmBtu
Northern Appalachia:	Pittsburgh Seam 13,000 Btu, <3.0 lbSO2/mmBtu	Uinta Basin in Colo.:	11,700 Btu, 0.8 lb SO2/mmBtu
Illinois Basin:	11,800 Btu, 5.0 lb SO2/mmBtu		

[1]Coal prices shown are for a relatively high-Btu coal selected in each region, for delivery in the "prompt quarter." The prompt quarter is the quarter following the current quarter. For example, from January through March, the 2nd quarter is the prompt quarter. Starting on April 1, July through September define the prompt quarter.
Source: With permission, selected from listed prices in Platts Coal Outlook, "Weekly Price Survey."
Note: The historical data file of spot prices is proprietary and cannot be released by EIA; see http://www.platts.com/Coal/.> Analytic Solutions > COALdat, or > Newsletters > Coal Outlook.

Previous Coal News and Markets Reports

Average Weekly Coal Commodity Spot Prices
(Dollars per Short Ton)

Week Ended	Central Appalachia 12,500 Btu, 1.2 SO2	Northern Appalachia 13,000 Btu, <3.0 SO2	Illinois Basin 11,800 Btu, 5.0 SO2	Powder River Basin 8,800 Btu, 0.8 SO2	Uinta Basin 11,700 Btu, 0.8 SO2
05/22/09	$43.50	$43.50	$45.00	$8.75	$42.00
05/29/09	$45.50	$43.50	$42.00	$8.75	$42.00
06/05/09	$45.50	$43.50	$42.00	$8.75	$42.00
06/12/09	$48.00	$43.50	$42.00	$8.75	$42.00
06/19/09	$48.00	$43.50	$42.00	$8.75	$42.00
06/26/09	$48.00	$43.50	$42.00	$8.75	$42.00
07/02/09	$50.05	$46.50	$42.00	$9.00	$45.00

View the Weekly Coal Production Report for the most recent week.
View the NYMEX Report for the most recent week.
View the Quarterly Coal Report for the most recent quarter.
View the most recent issue of the Annual Coal Report.
View an on-line summary of U.S. Coal Supply and Demand.
Sign up to automatically receive via Email.

Contact:
Fred Freme
Phone: 202 - 586-1251
E-Mail: Fred Freme
Fax: 202 - 287-1944

OPUC Data Request 36

Concerning PPL(TAM)/200, Lasich/2:

a. Please provide the 2009 and 2010 PPI and CPI forecasts that PacifiCorp uses to determine the escalation/de-escalation of indexed contracts. How does PacifiCorp's CPI forecasts compare to US Forecast, Global Insights 2009 CPI change of -1.9% and 2010 CPI Change of 1.7% (Total 2008 to 2010 change of 0.-14%)?

b. Please list the contracts that are indexed based on the CPI/PPI.

c. In the following table (Excel) format, please provide the following information. In addition, please indicate if the contract is indexed by the CPI, PPI, or combination of CPI and PPI.

Contract (Mine)	2008 Price/Ton	2009 Price/Ton	2010 Price/Ton

Response to OPUC Data Request 36

a. The Company did not use Global Insight's PPI or CPI projections to forecast escalation of indexed contracts. The Company instead used the following indices: (1) The diesel fuel related indices for the coal/transportation contracts were derived based on the NYMEX Heating Oil Contract Strip of March 6, 2009. (2) The natural gas related index was based on the Company's official price curve of December 31, 2008. (3) Average hourly earnings for coal mining were escalated at 3% annually, which is comparable to the Company's union agreement. (4) Non-diesel, non-labor related indices were escalated at 1.5% annually. The actual escalation of several of the Company's contract indices is at rates significantly greater than the producer prices by commodity escalation rates published by Global Insight.

b. Please refer to Attachment OPUC 36 b.

c. Please refer to Confidential Attachment OPUC 36 c. Confidential information is provided subject to the terms and conditions of the protective order in this proceeding.

Please refer to non-confidential Attachment OPUC 36b on the enclosed CD.

Please refer to Confidential Attachment OPUC 36c on the enclosed CD.

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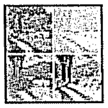

Short-Term Energy Outlook

June 9, 2009 Release
(Next Update: July 7, 2009)

Printer-friendly versions:
Full Report Text Only Tables Only Charts Only

Highlights | Global Crude Oil and Liquid Fuels | U.S. Crude Oil and Liquid Fuels | Natural Gas | Electricity | Coal

Highlights

- Spot prices for crude oil and petroleum products have increased over the past month. The price of West Texas Intermediate (WTI) crude oil is expected to average $67 per barrel for the second half of 2009, an increase of about $16 compared with the first half of the year.

- The average U.S. price for regular-grade gasoline, at $2.62 per gallon on June 8, was almost 60 cents per gallon higher than its price at the end of April. Regular-grade gasoline prices are expected to reach their summer seasonal peak in July, with a monthly average close to $2.70 per gallon. The annual average regular-grade gasoline retail price in 2009 is expected to be $2.33 per gallon, rising to $2.56 in 2010. The annual average diesel fuel retail prices are expected to be $2.40 and $2.67 per gallon in 2009 and 2010, respectively.

- The monthly average Henry Hub natural gas spot price is expected to stay under $4 per thousand cubic feet (Mcf) until late in the year as abundant natural gas supplies converge with weak demand driven by an 8-percent decline in industrial sector consumption. The price is projected to increase from an average of $4.13 per Mcf in 2009 to an average $5.49 per Mcf in 2010 as expected economic growth boosts industrial consumption of natural gas.

- Based on the current Atlantic hurricane season outlook from the National Oceanic and Atmospheric Administration (NOAA), EIA estimates expected production shut-ins on the U.S. Gulf Coast during the upcoming hurricane season (June through November) of about 4.5 million barrels for crude oil and 36 billion cubic feet for natural gas (see the *2009 Outlook for Hurricane Production Outages in the Gulf of Mexico*). Actual shut-ins are likely to differ significantly from this expectation depending on the number, track, and strength of hurricanes as the season progresses.

Global Crude Oil and Liquid Fuels

Overview. Oil prices rose for the third consecutive month in May, driven in part by expectations of a global economic recovery and future increases in oil consumption. In addition, a weaker dollar and increasing financial market activity are prompting higher prices for commodities, overshadowing weak oil supply and demand fundamentals. The weaker dollar may indicate that economic activity abroad, especially in Asia, is stronger than currently estimated, which would provide an upside risk to the oil price forecast. Downside risks, such as continuing weak demand as indicated by sluggish first quarter 2009 oil

STEO Special Report:

The 2009 Outlook for Hurricane Production Outages in the Gulf of Mexico

Price Summary

	Year				Percent Change		
	2007	2008	2009	2010	07-08	08-09	09-10
WTI Crude[a] ($/barrel)	72.32	99.57	*58.70*	*67.42*	37.7%	*-41.0%*	*14.8%*
Gasoline[b] ($/gal)	2.81	3.26	*2.33*	*2.56*	16.0%	*-28.3%*	*9.8%*
Diesel[c] ($/gal)	2.88	3.80	*2.40*	*2.67*	31.9%	*-36.9%*	*11.5%*
Heating Oil[d] ($/gal)	2.72	3.38	*2.49*	*2.66*	24.2%	*-26.4%*	*7.1%*
Natural Gas[d] ($/mcf)	13.03	13.67	*11.81*	*11.38*	4.9%	*-13.7%*	*-3.6%*

[a] West Texas Intermediate. [b] Average regular pump price.
[c] On-highway retail. [d] Residential average.

Detailed STEO Information:
° Custom Table Builder historical data, projections
° Real Petroleum Prices charts, data, projections

Related STEO Information:
° STEO Release Schedule
° Previous STEO Outlooks
° Special Analyses and Model Documentation
° Contact STEO Experts

Other EIA Forecasts:
° US Annual Energy Outlook
° International Energy Outlook

Standard Tables
- "Dynamic" table (HTML)
- printer-friendly table (PDF)
All Tables in a single Excel file

	HTML	PDF
SF01. U.S. Summer Fuels Outlook		
1. U.S. Energy Market Summary		
2. U. S. Energy Prices		
3a. International Crude Oil and Liquid Fuels Supply, Consumption, and Inventories		
3b. Non-OPEC Crude Oil and Liquid Fuels Supply		
3c. OPEC Crude Oil and Liquid Fuels Supply		
3d. World Liquid Fuels Consumption		
4a. U.S. Crude Oil and Liquid Fuels Supply, Consumption, and Inventories		
4b. U.S. Petroleum Refinery Balance		
4c. U.S. Regional Motor Gasoline Prices and Inventories		
4d. U.S. Regional Heating Oil Prices and Inventories		
4e. U.S. Regional Propane Prices and Inventories		
5a. U.S. Natural Gas Supply, Consumption, and Inventories		

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consumption data, high inventories, and increased surplus production capacity levels within the Organization of the Petroleum Exporting Countries (OPEC) could moderate the upward price pressure, especially if the global economic recovery is delayed and/or weaker than expected.

Consumption. World crude oil and liquid fuels consumption remains below year-ago levels. Total consumption during the fourth quarter of 2008 was 2.8 million barrels per day (bbl/d) below fourth quarter 2007 levels because of the global economic downturn. The year-over-year decline in total consumption increased in the first quarter of 2009 to an estimated 3.4 million bbl/d. Oil consumption in countries that are members of the Organization for Economic Cooperation and Development (OECD) fell by 2.4 million bbl/d in the first quarter of 2009, compared to the first quarter of 2008, accounting for more than 70 percent of the total decline. The rate of consumption decline is expected to moderate later in the year. After falling by an average 1.8 million bbl/d in 2009, global consumption is projected to grow by 0.7 million bbl/d in 2010 in response to expected positive global economic growth (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. After falling by 270,000 bbl/d in 2008, total non-OPEC supply is projected to rise by 400,000 bbl/d in 2009 and remain almost flat at the 2009 level in 2010. Over the forecast period, higher output in a few countries, such as Brazil, the United States, and Azerbaijan, is expected to offset declining production in Mexico, the North Sea, and Russia (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart).

OPEC Supply. OPEC crude oil production is estimated to have averaged approximately 28.7 million bbl/d in the first quarter of 2009 and is projected to average 28.6 million bbl/d in the second quarter. This represents a roughly two-thirds compliance rate with announced production cuts. OPEC, which held production targets steady at its May 28 meeting, plans to meet again on September 9 in Vienna to review market conditions. Over the forecast period, prospects for an economic recovery and a rebound in oil consumption signal higher demand for OPEC oil.

OPEC crude oil production is projected to average 28.5 million bbl/d in 2009, before rising slightly to 28.8 million bbl/d in 2010. However, OPEC production capacity is expected to rise by 1.2 million bbl/d by the end of next year, relative to the end of 2008, which will increase surplus production capacity and help mitigate upward price pressure.

Inventories. Revised data indicate that OECD commercial inventories at year-end 2008 stood at 2.7 billion barrels. At 57 days of forward cover, OECD commercial inventories were well above average levels for that time of year (Days of Supply of OECD Commercial Stocks Chart). Preliminary estimates suggest that OECD commercial inventories increased by 46 million barrels during the first quarter of 2009, rather than declining seasonally, reaching 60 days of forward cover. The United States was responsible for this counter-seasonal build in OECD commercial inventories, with other OECD-member commercial stocks declining slightly. However, with the expected global demand increase in 2010 not forecast to be fully matched by increased supply, global inventories are expected to fall slightly over the forecast period.

U.S. Crude Oil and Liquid Fuels

Consumption. Based on the weak economy, total consumption of liquid fuels and other petroleum products is projected to contract by 550,000 bbl/d (2.9 percent) in 2009 (U.S. Petroleum Products Consumption Growth Chart), including a decline of 220,000 bbl/d (5.5 percent) in distillate fuel consumption and about 100,000 bbl/d (6.9 percent) in jet fuel consumption. Motor gasoline, however, is projected to increase by 30,000 bbl/d (0.3 percent) as a result of the substantial declines in retail prices from last summer and the stabilization of real disposable income. The gradual economic recovery in 2010 is expected to contribute to a 300,000-bbl/d (1.6 percent) increase in total liquid fuels consumption.

Production. Total domestic crude oil production averaged 4.96 million bbl/d in 2008, down from 5.06 million bbl/d in 2007 (U.S. Crude Oil Production Chart). Production is expected to increase to an average of 5.27 million bbl/d in 2009 and 5.32 million bbl/d in 2010, including an estimated expectation, with a wide range of uncertainty, of hurricane-induced outage of about 4.5 million barrels for the offshore region in 2009 (see the *2009 Outlook for Hurricane Production Outages in the Gulf of Mexico*).

Figures - chart only (GIF)
- chart and data in an Excel spreadsheet
All figures and data in a single Excel file

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Prices. WTI crude oil prices, which averaged $99.57 per barrel in 2008 (Crude Oil Prices Chart), are projected to average $58.70 per barrel in 2009 and $67.42 per barrel in 2010. As always, energy price forecasts are highly uncertain. One measure of how the market reflects this uncertainty is the sizable participation in near-term options on crude oil futures contracts at strike prices that are significantly different from current futures market prices. This reflects the tendency for crude oil prices to fluctuate within a wide range in a relatively short period.

EIA projects that regular-grade motor gasoline retail prices, which averaged $3.26 per gallon in 2008, will average $2.33 per gallon this year, up 21 cents per gallon from last month's *Outlook* projection. These prices are projected to rise to $2.56 per gallon in 2010, 26 cents above that projected in the previous *Outlook*. Diesel fuel retail prices, which averaged $3.80 per gallon in 2008, are projected to average $2.40 per gallon in 2009, up 14 cents from the previous *Outlook*. Diesel fuel retail prices are projected to average $2.67 per gallon in 2010, up 19 cents per gallon from the previous *Outlook*.

Natural Gas

Consumption. Total natural gas consumption is projected to decline by 2.2 percent in 2009 and then increase slightly in 2010 (Total U.S. Natural Gas Consumption Growth Chart). While total natural gas consumption remains hampered by the broad economic downturn, the persistence of low natural gas prices into the fourth quarter of 2009 is expected to lead to a 2.7-percent increase in electric power sector consumption in 2009, offsetting a portion of the 8-percent decline expected in industrial sector consumption. Additional declines expected in the residential and commercial sectors this year also contribute to the lower 2009 consumption estimate. The anticipation of some economic recovery in 2010 is the basis for slight consumption increases in the commercial and industrial sectors next year, with little change expected in the residential sector. Furthermore, if the dollar remains weak and natural gas prices remain relatively low, consumption in the industrial sector may be bolstered by increased exports of natural-gas-intensive products. Finally, consumption in the electric power sector is expected to remain flat in 2010 as natural gas prices rise relative to coal prices.

Production and Imports. Total U.S. marketed natural gas production is expected to decline by 1.1 percent in 2009 and by 2.6 percent in 2010. Low natural gas prices brought about by the current economic slump have had a dramatic impact on recent drilling activity. According to Baker Hughes, total working natural gas rigs are now down 56 percent from the September 2008 peak. Although a corresponding decline in production has yet to appear in data through March 2009, total U.S. marketed production is expected to drop by nearly 5 billion cubic feet (Bcf) per day between the first and fourth quarters of 2009. The decline in annual production is expected to occur almost exclusively in the Lower-48 non-Gulf of Mexico (GOM) this year, more than offsetting the small expected increase in GOM output. This projection includes an estimated expectation of hurricane-induced outage of about 36 Bcf for the offshore region in 2009 (see the *2009 Outlook for Hurricane Production Outages in the Gulf of Mexico*)

The lagged effect of this year's drilling pullback is also expected to result in lower natural gas production in 2010. However, EIA does not anticipate that working rigs and natural gas prices need to return to 2008 levels for production to increase. Recent improvements in technology have reduced finding and development costs, lowered completion times, and greatly enhanced well productivity, increasing the production potential from domestic sources. As a result, production is expected to respond adequately, with a shorter lag, to sustained increases in demand.

U.S. liquefied natural gas (LNG) imports are expected to increase to about 495 Bcf in 2009, from 352 Bcf in 2008, due to weakness in demand for LNG in the global market. The severe economic contractions in the LNG-consuming countries of Asia have increased the amount of available LNG in the global market, elevating LNG purchases in Europe, where natural gas prices remain slightly above those in the United States. In the coming months, as storage facilities in Europe are replenished and new liquefaction capacity comes online, available LNG cargoes are expected to be directed to U.S. terminals. While there is still a degree of uncertainty associated with the start-up of new liquefaction capacity and the availability of shipments, higher than expected LNG imports

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would almost certainly have a dampening effect on prices and cause lower domestic natural gas production or pipeline imports.

Inventories. On May 29, 2009, working natural gas in storage was 2,337 Bcf (U.S. Working Natural Gas in Storage Chart). Current inventories are now 423 Bcf above the 5-year average (2003–2007) and 546 Bcf above the level during the corresponding week last year. The estimated inventory build in May was 465 Bcf, the largest increase for this particular month since at least 1976, when records were first kept. Working natural gas stocks are now expected to reach 3,659 Bcf at the end of the 2009 injection season (October 31), roughly 94 Bcf above the previous record of 3,565 Bcf reported for the end of October 2007.

Prices. The Henry Hub spot price averaged $3.96 per Mcf in May, $0.33 per Mcf above the average spot price in April. Prices remain low as natural gas supplies continue to seep into a weak market. As working natural gas inventory nears storage capacity limits, prices may need to decline further to induce necessary adjustments in supply or stimulate demand. Anticipated economic recovery and seasonal space-heating demand are expected to contribute to some price strength in early 2010, and enhanced production capability from domestic supply sources is expected to limit sustained upward price movements throughout the forecast period. The Henry Hub spot price is expected to average $4.13 per Mcf in 2009 and $5.49 per Mcf in 2010.

Electricity

Consumption. During the first quarter of 2009, total consumption of electricity fell by an estimated 3 percent compared to the same period last year primarily because of weak industrial consumption. Growth in residential retail sales during the second half of this year is expected to slightly offset continued declines in industrial electricity sales. Total consumption is projected to fall by 1.8 percent for the entire year of 2009 and then rise by 1.2 percent in 2010 (U.S. Total Electricity Consumption Chart).

Prices. Retail residential electricity prices increased an estimated 8 percent during the first quarter of 2009 compared to the first quarter of 2008 (U.S. Residential Electricity Prices Chart) because of regulatory lags in the pass-through of fuel costs. However, lower fuel costs for generation are expected to be passed through to retail consumers later this year, keeping the annual 2009 growth in prices around 5.0 percent. Residential prices are expected to grow by just 2.4 percent during 2010.

Coal

Consumption. A decline in overall electricity generation, combined with projected increases from natural gas, nuclear, and renewable (hydroelectric and wind) generation sources, are projected to lead to a 4.6-percent decline in coal consumption in the electric power sector this year. The projected electric power sector consumption of 994 million short tons (MMst) in 2009 is the first time since 2002 that annual consumption would be below the billion short ton level. An expected increase in total electricity generation of 1.5 percent in 2010 is expected to lead to a 1.7-percent increase in electric-power-sector coal consumption. Non-power-sector coal consumption, for both steam and coke production, is projected to decline by 33 percent in 2009, reflecting very weak industrial activity (U.S. Coal Consumption Growth Chart).

Production. Production is expected to fall by about 7 percent in 2009 in response to lower total domestic coal consumption, export declines, and high coal inventories. The April 2009 production estimate of 88.3 MMst is the lowest monthly coal production figure since May 2004. Conversely, the estimated March 2009 secondary coal inventories of 183.9 MMst is the highest in over 20 years (secondary inventories were 185.5 MMst in December 1987). Production is projected to increase slightly (0.6 percent) in 2010 as domestic consumption and exports increase with an improving economy (U.S. Annual Coal Production Chart).

Exports. Reductions in global coal demand are expected to reduce U.S. coal exports by about 16.5 million short tons, a 20-percent decrease, in 2009. The projected rebound in global economic activity is expected to increase global coal demand and lead to a 24-percent increase in exports in 2010.

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Prices. Despite declines in electricity demand and lower fuel costs, the annual average delivered coal price is projected to increase to $2.16 per million Btu (MMBtu) in 2009 due to a pricing lag between mine-mouth and delivered coal prices caused by long-term coal contracts. Current delivered prices were set when contracts were entered into during a period of high prices for all fuels one year or more ago. Although record increases in spot prices (some well over 100 percent) for several types of coal contributed to the increase in the cost of coal, spot market purchases make up only a small portion of total coal consumed. The average delivered coal price is expected to decline to $1.98 per MMBtu in 2010, as expiring high-priced contracts are replaced.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UI 189

In the Matter of the Application of PACIFICORP for Approval of a Coal Supply Agreement with BRIDGER COAL COMPANY.	))))	ORDER

DISPOSITION: APPLICATION APPROVED WITH CONDITIONS

On January 26, 2001, PacifiCorp filed an application with the Public Utility Commission of Oregon (Commission) pursuant to ORS 757.495 and OAR 860-027-0040 requesting approval of its coal supply agreement with Bridger Coal Company (BCC), an Affiliated Interest.

Based on a review of the application and the Commission's records, the Commission finds that the application satisfies applicable statutes and administrative rules. At its Public Meeting on May 22, 2001, the Commission adopted Staff's recommendation to approve the application with certain standard conditions. Staff's recommendation is attached as Appendix A, and is incorporated by reference.

OPINION

Jurisdiction

ORS 757.005 defines a "public utility" as anyone providing heat, light, water or power service to the public in Oregon. The Company is a public utility subject to the Commission's jurisdiction.

Affiliation

An affiliated interest relationship exists under ORS 757.015.

Applicable Law

ORS 757.495 requires public utilities to seek approval of contracts with affiliated interests within 90 days after execution of the contract. The intent of the statute is to protect ratepayers from the abuses which may arise from less than arm's length transactions. *Portland General Electric Company*, UF 3739, Order No. 81-737 at 6. Failure to file within the 90-day time limit may preclude the utility from recovering costs incurred under the contract.
See ORS 757.495.

ORS 757.495(3) requires the Commission to approve the contract if the Commission finds that the contract is fair and reasonable and not contrary to the public interest. However, the Commission need not determine the reasonableness of all the financial aspects of the contract for ratemaking purposes. The Commission may reserve that issue for a subsequent proceeding.

CONCLUSIONS

1. The Company is a public utility subject to the jurisdiction of the Commission.

2. An affiliated interest relationship exists.

3. The agreement is fair, reasonable, and not contrary to the public interest.

4. The application should be granted, with conditions.

ORDER

IT IS ORDERED that the application of PacifiCorp for authority to engage in a Coal Supply Agreement with Bridger Coal Company, is granted, subject to the conditions stated in Appendix A.

Made, entered, and effective ________________________.

BY THE COMMISSION:

____

Vikie Bailey-Goggins
Commission Secretary

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A party may appeal this order to a court pursuant to ORS 756.580.

ITEM NO.___

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: MAY 22, 2001

REGULAR AGENDA___ CONSENT AGENDA_X_ EFFECTIVE DATE________

DATE: May 16, 2001

TO: Phil Nyegaard through Marc Hellman and Mike Myers

FROM: Tom Riordan

SUBJECT: UI 189 – PacifiCorp Application for approval of a Coal Supply Agreement with Bridger Coal Company, Inc. (BCC), an Affiliated Interest

SUMMARY RECOMMENDATION:

I recommend approval of the requested agreement with the conditions noted in the detailed recommendation.

DISCUSSION:

Background:

PacifiCorp filed this application on January 26, 2001, pursuant to ORS 757.495 and OAR 860-027-0040. The company seeks a Commission order finding that since 1979, its coal supply agreement with BCC, has previously been considered and approved in its prior general rate cases. Alternatively, PacifiCorp, in an effort to eliminate any questions of compliance with statutory requirements governing affiliate transactions, seeks a Commission order approving its coal supply agreement with BCC.

PacifiCorp owns a two-thirds interest in the Jim Bridger coal-fired steam electric generating plant in Wyoming. This generating plant obtains a substantial majority of its needed coal supply from BCC, a joint venture owned one-third by an Idaho Power Company subsidiary and two-thirds by Pacific Minerals, Inc.(PMI), an indirect wholly owned subsidiary of PacifiCorp. The joint venture owns significant leases covering coal deposits located near the Jim Bridger generating plant. Affiliated interest relationships exist between PacifiCorp and BCC, and between PacifiCorp and PMI.

Currently, the PacifiCorp and BCC relationship is governed by the Third Restated and Amended Coal Sales Agreement, dated January 1, 1996 (Third Restated Agreement) and the First Amendment thereto of January 1999. Together they are known as the Coal Supply Agreement. The agreement establishes annual base tonnages for coal purchases

which for 2000 and 2001 are 5,232,600 on a total system basis. Coal prices are determined through establishment of component base price, consisting of several costs related to BCC coal operations, as adjusted pursuant to the price change provision in the agreement.

The company states that BCC coal provides it with advantages such as a consistently reliable coal source and a minimization of fuel transportation and handling costs. Historically, from 1990 through 1999, the average cost of coal provided by the Coal Supply Agreement ranged from \$3 to \$9 per ton less than the average market price of Southern Wyoming coal delivered to the plant.

Therefore, PacifiCorp believes that the Coal Supply Agreement provides it with a reliable, long-term source of low-cost coal for the operation of the Jim Bridger generation plant. Further, the company states that since it was limited, for ratemaking purposes, to prudently incurred coal expenses plus a reasonable return on the Company's coal investment, the Commission should determine that the Coal Supply Agreement is not contrary to the public interest. Staff believes that the appropriate standard the Commission has used and continues to use for ratemaking is its affiliate interest transfer-pricing requirements, namely that the price is the lower of cost or fair market rate. See further discussion below.

Issues

I have investigated the following issues:

1. Scope and Terms of Agreement
2. Transfer Pricing and Allocation Methods
3. Public Interest Compliance
4. Records Availability, Audit Provisions, and Reporting Requirements

Scope and Terms of Agreement – Based upon my analysis of the agreement, there appear to be no unusual or restrictive terms that would harm customers. Accordingly, I am not concerned about this issue.

Transfer Pricing and Allocation Methods – The Commission's transfer policy for goods and services purchased by a regulated electric utility from an affiliate shall be priced at the lower of cost or fair market rate. This policy likely has been met because BCC is charging PacifiCorp a price for its coal supply based on BCC's fully distributed cost that is currently less than the market rate. The company's rate of return used in billing from BCC to PacifiCorp is at the same rate authorized by the Commission in PacifiCorp's most recent rate case. This is consistent with the Commission's affiliated interest (AI) transfer pricing policy. Proposed ordering condition No. 4 is included to ensure that PacifiCorp adheres to the Commission's policy.

Public Interest Compliance – PacifiCorp's customers are likely not harmed by this transaction, because the company is paying, with the provision of my proposed ordering condition No. 4, a fair and reasonable price for the coal supply. Therefore, the purchase price meets the lower of cost or fair market requirement of the Commission AI transfer pricing policy. Also, Staff noted that in 2000 and estimates for 2001, the average price savings per ton to PacifiCorp from the BCC Coal Supply Agreement are trending lower. If there should be a further lowering of the savings to PacifiCorp and its customers, it may necessitate a modification to the transfer price to meet the Commission's AI policy. This would then require PacifiCorp to comply with proposed ordering condition No. 3 to protect the public's interest.

Records Availability, Audit Provisions, and Reporting Requirements – Proposed ordering condition No. 1 provides the necessary records access to BCC's relevant books and records

CONCLUSIONS:

Based on an investigation and review of the application, I conclude the following:

1. PacifiCorp is a regulated electric company, subject to the jurisdiction of the Public Utility Commission of Oregon.

2. An affiliated interest relationship exists between PacifiCorp and Bridger Coal Company.

3. The application is fair and reasonable and not contrary to the public interest.

DETAILED RECOMMENDATION:

I recommend that the Commission approve PacifiCorp's alternative request, namely, the application of PacifiCorp for a Coal Supply Agreement with Bridger Coal Company, an affiliated interest and include the following standard Commission conditions in this matter:

1. PacifiCorp shall provide the Commission access to all books of account, as well as all documents, data, and records of PacifiCorp and BCC's affiliated interests which pertain to transactions between PacifiCorp and BCC.

2. The Commission reserves the right to review for reasonableness all financial aspects of this arrangement in any rate proceeding or alternative form of regulation.
3. PacifiCorp shall notify the Commission in advance of any substantive changes to the agreement, including any material changes in any cost. Any changes to the terms which alter the intent and extent of activities under the agreement from those approved herein shall be submitted in an application for a supplemental order (or other appropriate format) in this docket.
4. For accounting purposes, the return component used in calculating PacifiCorp's cost of service received from BCC shall be limited to the PacifiCorp's current authorized overall rate of return.

OPUC Data Request 51

Concerning PPL (TAM)/200, Lasich/4-5:

a. Concerning the higher costs in 2010, approximately how much of the variance from 2009 costs is attributable to dragline mining?
b. Will dragline mining be the method to surface mine in subsequent years? Please explain.
c. Approximately how much of the variance from 2009 costs is attributable to EITF 04-6?
d. Does PacifiCorp anticipate extracting more coal than uncovered in 2011? Please explain.
e. Has PacifiCorp been provided with an estimated/budgeted 2011 surface mining cost from BCC? If so, please provide and explain the estimated/budgeted cost.

Response to OPUC Data Request 51

a. Bridger Coal Company 2010 test period costs are $33.54 with EITF 04-6 and $30.63/ton without EITF 04-6. The 2009 forecast of $30.57 would increase to $30.69/ton without EITF 04-6. The impact of EITF 04-6 accounts for almost all of the variance in Bridger Coal Company mine costs between 2009 and 2010.

b. Yes, the supply of coal from Bridger Coal Company to the Jim Bridger Plant will include coal production from the underground and surface mines. The draglines will continue to be used by Bridger Coal Company to remove overburden.

c. See Response OPUC 51.a above. The impact on PacifiCorp of EITF 04-6 is to increase Bridger Coal Company costs in 2010 by $10.86 million and to decrease 2009 costs by $.48 million in 2009.

d. PacifiCorp does not have a current 2011 mine plan for Bridger Coal Company. Bridger Coal Company is in the process of developing a long-term mine plan. The 2011 mine plan, including both tonnage uncovered and extracted, will not be available until later this fall.

e. See above.

OPUC Data Request 39

Concerning PacifiCorp's responses to Staff Data Requests Nos. 3 and 6, please explain the "*Bridger Coal Incr.*" tons.

a. Why isn't this amount included in the tons delivered in Attach OPUC 3 CONF?

b. Please explain the 2007, 2008, and 2009 amounts for "*Bridger Coal Incr.*" tons.

Response to OPUC Data Request 39

a. Bridger Coal Incremental signifies a spot coal supply for the Bridger Plant. A spot coal supply is required when Bridger Plant mmbtu requirements are in excess of the mmbtu supplied under the Black Butte contract and Bridger Coal Company's 2010 fueling plan. The filing assumes that the coal would be supplied on an incremental basis from Bridger Coal rather than from the Powder River Basin. The tons are not included in OPUC 3 because these volumes are in excess of Bridger Coal Company's 2010 fueling plan. The associated Bridger Coal Incr. price is an estimate of the incremental cost to supply the coal from the Bridger Mine surface operation.

b. On an actual basis there is no Bridger Coal Incremental. Historical costs and deliveries for Bridger Coal reflect all Bridger coal deliveries.

   Bridger Coal Incremental information was provided in response to TAM Support 2, F.

OPUC Data Request 37

Based on current equipment, labor, and process for Bridger Mine, what is the approximate capacity (tons) that can be mined through underground operations? Please provide the largest monthly amount mined through underground operations to date.

Response to OPUC Data Request 37

The test period reflects the full capacity of the underground operation in 2010 - 4,633,943 tons of underground coal will be delivered to the Bridger Plant. The Bridger underground mine produced a high of 509,481 tons in August 2008; however, this tonnage level is not representative of an annual run rate due to longwall moves and longwall panel development.

ORDER NO. 91-513

ENTERED APR 12 1991

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UI 105

In the Matter of the Application of PACIFICORP, dba PACIFIC POWER & LIGHT COMPANY, for an order approving a contract for mining services with Energy West Mining Company, an affiliated interest.	)))))	ORDER

DISPOSITION: GRANTED

On January 2, 1991, Pacific Power & Light Company, an assumed business name of PacifiCorp (Pacific or company), filed an application with the Public Utility Commission pursuant to ORS Chapter 757 and OAR 860-27-040. The company requested approval of a contract for mining services (contract) with Energy West Mining Company (EWMC), effective for accounting purposes as of October 1, 1990.

The Commission makes the following:

FINDINGS OF FACT

Jurisdiction

Pacific is an Oregon corporation duly qualified to transact business in the state of Oregon. Pacific engages in the generation, purchase, transmission, distribution, and sale of electric energy to the public in the state of Oregon. EWMC is a wholly owned subsidiary of PacifiCorp. Pacific and EWMC have four directors and/or officers in common.

The Proposal

Pacific has entered into a contract with EWMC dated October 1, 1990, to provide mining services at the Cottonwood, Deer Creek, and Des-Bee-Dove coal mines, which are now wholly owned by Pacific. Under the contract, EWMC will operate these coal mines and mine coal in the quantities and according to the specifications requested by Pacific.

Other responsibilities of EWMC include the maintenance of safe working conditions and appropriate safety equipment at the mines, and the operation of the mines in accordance with all applicable laws and regulations. Additional services associated with the fueling of the Hunter and Huntington steam plants, as requested by Pacific, will also be performed by EWMC.[1]

Pacific will loan operating capital to EWMC. The outstanding amount of these loaned funds will not exceed $5 million at any time. EWMC will pay interest to Pacific on loaned funds on the terms set forth in and at a rate equal to that established under the Umbrella Loan Agreement dated April 4, 1983, among PacifiCorp and certain of its affiliates. All equipment and facilities reasonably necessary for the performance of EWMC's obligations will be made available without charge by Pacific.

EWMC will not acquire real property or depreciable assets with a value in excess of $1,000. EWMC will be reimbursed only for its actual reasonable expenses, and those expenses will not include a return on investment. EWMC will be responsible for the inspection and maintenance of all equipment and facilities made available by Pacific. EWMC will maintain books and records consistent with generally accepted accounting principles, and will make its books and records available for inspection by Pacific at any time. EWMC is precluded from engaging in any activities unrelated to the contract.

Pacific estimates that the annual cost of performing the agreement functions will be approximately $67 million, based on mining approximately 6.7 million tons of coal, on a total company basis. On an Oregon allocated basis, the annual contract cost estimate is approximately $19 million. The agreement is for the five year period from October 1, 1990, through September 30, 1995, and may be extended by Pacific for successive five year terms.

According to a current strategic energy policy report by outside energy experts, Pacific has recently been successful in reducing costs at its affiliate mines, include the Utah mines operated by EWMC. This has resulted in Pacific's Utah-mined coal being purchased at or below market prices.

EWMC has been established in a manner so that it will not earn a profit. It is unlikely that a third party could provide services at a lower cost.

There is no indication that the proposal will impair Pacific's ability to provide its public utility service.

[1]Pacific owns 84.7 percent of the Hunter plant and 100 percent of the Huntington plant.

Pacific proposes that, for accounting purposes, the agreement be approved as of October 1, 1990. This will enable Pacific to maintain its books in conformance with regulatory requirements.

The Commission's staff investigated the arrangement between Pacific and EWMC and recommended that the Commission approve the application. At its public meeting on March 19, 1991, the Commission adopted the staff recommendation.

OPINION

The following statutes are applicable to this application:

ORS 747.005 defines a public utility as, inter alia, an entity which owns, operates, manages, or controls all or part of any plant or equipment in this state for the production, transmission, delivery, or furnishing of heat, light, or power, directly or indirectly to the public. Pacific is a public utility subject to the Public Utility Commission's jurisdiction.

ORS 757.015(5) defines an "affiliated interest" as "every corporation which has two or more officers or two or more directors in common with such public utility." EWMC and Pacific have four officers and/or directors in common; therefore an "affiliated interest" relationship exists.

ORS 757.495 provides that no public utility shall contract with an affiliated interest for services without the Commission's approval. The statute was designed to protect utility customers from abuses which may arise from less than arm's length transactions. CP National Corporation, UF 3842, Order No. 82-593 at 2; Portland General Electric Company, UF 3739, Order No. 81-737 at 6. The standard of review is whether the proposed contract is ". . . fair and reasonable and not contrary to the public interest . . . ." See ORS 757.495(3).

The application should be granted. The agreement with EWMC will benefit Pacific's customers because it will promote safe and efficient operation of the Cottonwood and Deer Creek mines and a lower overall generation cost at the Hunter and Huntington steam plants.

Pacific will reimburse EWMC for all reasonable expenses incurred by EWMC in the performance of its obligations. EWMC shall bill Pacific only actual costs for its services.

This cost-based approach and the limitation of EWMC's activities to those arising under the contract minimize the likelihood of cross-subsidization. Due to recent reductions in operating costs at EWMC's Utah mines, Pacific is purchasing coal at or below market prices. Through the rate-making process, the Commission can ensure that Oregon utility customers do not pay unreasonable expenses. The Commission concludes that the agreement is fair and reasonable and not contrary to the public interest.

Pacific's contract with EWMC is not recognized for rate-making purposes until approved by the Commission in a future rate-making proceeding. ORS 757.495(3). Retroactive approval of the accounting treatment is appropriate due to cost accounting considerations. Expenditures made should be charged to accounts in the manner directed by Federal Energy Regulatory Commission Regulations and the Commission's rules.

CONCLUSIONS OF LAW

1. Pacific is a public utility subject to the jurisdiction of the Public Utility Commission.

2. An affiliated interest relationship exists between Pacific and EWMC.

3. The agreement between Pacific and EWMC is fair and reasonable and not contrary to the public interest.

ORDER

IT IS ORDERED that:

1. The application of Pacific for approval of its contract dated October 1, 1990, with the Energy West Mining Company, is granted. This approval shall be effective for accounting purposes as of October 1, 1990.

2. Pacific shall provide staff access to all books of account, as well as all documents, data, and records of Pacific, and Pacific's affiliated interests which pertain to the transactions between Pacific and EWMC.

3. Pacific shall notify the Commission in advance of any substantive changes to the level, type, terms, or conditions of transactions executed under the subject contract. Any changes which alter the intent or extent of activities under the contract from those approved in this order shall be submitted for approval

in an application for a supplemental order (or other appropriate format) in this docket.

4. Pacific shall comply with the annual reporting requirements for affiliated interest transactions.

5. Pacific shall timely notify the Commission of all management studies and/or analyses, internal or external audit reports, and any related studies or reports pertaining to the agreement between Pacific Electric Operations and Energy West Mining Company, and shall promptly provide such information to the Commission upon request.

6. The Commission reserves the right to review for reasonableness all financial aspects of this arrangement in any subsequent rate proceeding.

Made, entered, and effective APR 12 1991.

BY THE COMMISSION:

Nancy Towslee
Commission Secretary

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order within 60 days from the date of service pursuant to ORS 756.561. A party may appeal this order pursuant to ORS 756.580.

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OPUC Data Request 31

As a follow-up to PacifiCorp's response to Staff Data Request No. 5:

a. Please explain the status of Deer Creek Coal sales to Carbon.
b. Please explain the variation in coal prices of Deer Creek Coal to the Hunter and Huntington plants. Please provide work papers that demonstrate the cost components.
c. Are the average coal and transportation costs a weighted average cost (i.e., Bridger)? Please explain.

Response to OPUC Data Request 31

The Company does not "sell" Deer Creek coal to the Carbon. The Deer Creek Mine is a Company asset – Deer Creek Mine operating costs are recorded as fuel costs. All Deer Creek coal is initially delivered to the Huntington Plant. Any transfers of Deer Creek coal to the Hunter Plant or Carbon Plant are recorded at the average Deer Creek operating cost for that month.

a. The 2010 Regulatory Fuel budget does not reflect any transfers of Deer Creek coal from the Huntington Plant to the Carbon Plant. In prior years, a minimal amount of Deer Creek coal was transferred to the Carbon Plant from the Huntington Plant while a corresponding minimal amount of Dugout coal was redirected from the Carbon Plant to the Huntington Plant. The Dugout coal allowed the Huntington Plant to mitigate the low ash fusion temperature of Deer Creek coal through blending. Inclusion of a transfer of Deer Creek coal to the Carbon Plant and a corresponding transfer of Dugout coal to Huntington would result in increased 2010 TAM coal costs due to additional transportation expense.

b. The variation between Deer Creek coal to the Hunter and Huntington Plants can be attributed to the following. First, any transfer of Deer Creek coal to Carbon and Hunter include the cost to load coal trucks at the Huntington Plant. Second, transfers of coal to Carbon or Hunter do not occur at an equal pro-rata basis throughout the year. Please see Confidential Attachment OPUC 31 b for a demonstration of the cost differences for 2010. Confidential information is provided subject to the terms and conditions of the protective order in this proceeding. This information was previously provided in the Utah Supplies Section of the Regulatory Fuel Budget (See response to TAM Support 2, F).

c. The coal and transportation costs provided in Confidential Attachment OPUC 5 reflect weighted averages.

Please refer to Confidential Attachment OPUC 31b on the enclosed CD.

94-1550 ITEM NO. CA 6

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PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: October 11, 1994

REGULAR AGENDA___ CONSENT AGENDA_X_ EFFECTIVE DATE ___________

DATE: October 5, 1994

TO: Mike Kane through Phil Nyegaard and Mike Myers

FROM: Tom Riordan

SUBJECT: UI 140--Pacific Power & Light Company (PP&L), abn of PacifiCorp, Application for Approval of a Fuel Agreement, Final Reclamation Agreement and Shareholder Funding Agreement with Trapper Mining, Inc. (Trapper), an Affiliated Interest (AI)

SUMMARY RECOMMENDATION:

Staff recommends approval, with conditions, of the company's AI application.

DISCUSSION:

Introduction

On July 25, 1994, PP&L filed an AI application for approval of agreements with Trapper to purchase fuel (coal), obtain final reclamation services and provide shareholder funding. PP&L and Trapper are affiliated interests under ORS 757.015(5) and (6), respectively, in that PP&L owns 19.3 percent of the voting control of Trapper and has two common officers with Trapper. PP&L requests that the Commission approve the agreements for accounting purposes, effective April, 1992, when PP&L acquired its interest in Trapper.

History and Background

PP&L acquired its interest in Trapper Mining, Inc. from Colorado-Ute Electric Association (Colorado-Ute), which along with three other entities were the original owners. These parties on March 1, 1973 executed the Craig Station Fuel Agreement (Fuel Agreement) with Utah International, Inc. The Fuel Agreement, which will end July 1, 2014, covered coal provision from Trapper mine to the Craig Generating Station in Utah. In 1983, these original owners purchased Trapper and formed Williams Fork Company to hold Trapper's assets. Colorado-Ute in March, 1990 filed a Chapter 11 bankruptcy petition. Under a Joint Plan in the bankruptcy proceeding which the court accepted, PacifiCorp acquired approximately 67 percent of Colorado-Ute's stock in Williams Fork Company. As a result of this transaction, PP&L (PacifiCorp) controls 19.28 percent of Trapper.

PP&L, under the Fuel Agreement, second supplement, March 1, 1992, pays Trapper about $18 per ton or approximately $7.5 million annually on a total company basis and about $2.26 million on an Oregon basis. The estimated cost to PP&L for Trapper coal for 1994 and 1995 is about $2.29 and $2.23 million, respectively, on an Oregon basis. A system energy factor is used to allocate the coal cost which is recorded in FERC account 151, Fuel Stock.

In addition to the Fuel Agreement, there is the Final Reclamation Services Agreement, which establish a mechanism to reimburse Trapper for costs of performing the reclamation work that may be required at Trapper mine following the termination of surface mining operations and to establish a fair method for allocating such costs when they are known and incurred. PP&L's portion of such costs is likewise 19.28 percent, based on the Fuel Agreement. Currently, it is estimated that PP&L's share of these future costs would be about $2.9 million.

The last agreement, dated March 1, 1992, is the Shareholder Funding Agreement which provides a mechanism for providing capital necessary to cover operating budget shortages of Trapper. To date, no such shortages have occurred. PP&L would be responsible for 19.28 percent of the shortages, if they occur. Proposed order condition no. 5 requires PP&L to promptly notify the Commission of the full details of any such occurrence.

<u>Issues</u>

Staff has investigated the following issues:

1. Scope of Services
2. Transfer Pricing and Cost Allocation
3. Demonstration of Public Interest Compliance
4. Records Availability, Audit Provisions, and Reporting Requirements

<u>Scope of Services</u>--The agreements' services of providing fuel (coal) and final reclamation, although essential to PP&L's proper provision of electric utility service at its Craig Generating Station, are not considered to be a transfer of any of PP&L's basic management functions to Trapper. These agreement services will only enhance PP&L's ability to adequately perform its utility functions.

<u>Transfer Pricing and Cost Allocation Procedures</u>--The Commission's transfer pricing policy for goods or services purchased from an affiliate by a regulated utility is that the goods or services shall be priced at the lower of cost or market. This policy likely has been met in this agreement between PP&L and Trapper, because the Fuel

Agreement was originally negotiated as an " arms length " contract and presently operates under the same terms and conditions. However, the transfer price PP&L pays to Trapper for coal seems to include a return component higher than PP&L's current Oregon-authorized 10.24 percent overall rate of return. This issue is diminished by fuel cost reductions resulting from Trapper's operating efficiencies at its mine. The reductions are passed on to PP&L and the other owners. To alleviate any transfer price concern, I have proposed order condition no. 4 which requires PP&L to limit the return component in Trapper's cost of service to PP&l's current Oregon-authorized overall return.

In addition, staff believes, due to the nature of the services and the cost of the arrangement with Trapper, that it is reasonable that PP&L would select Trapper rather than an external source.

Demonstration of Public Interest Compliance--PP&L's ratepayers are likely not harmed by this transaction because the utility will be paying a cost of service rate that is a market rate for the services from Trapper. Also, PP&L's total operating cost with the adjusted return component for the services is not more than what PP&L's cost would be to provide the same services on its own. Trapper's larger operation attains economies of scale and results in a lower cost of service than PP&L would alone.

Records Availability, Audit Provisions, and Reporting Requirements--Staff believes that the basic agreements contain provisions that allow the Commission adequate access to records and provision for auditing transactions between PP&L and Trapper. Also, condition No. 1 provides staff full records access.

Conclusion

Based upon staff's investigation and review of this request, I conclude the following:

1. Pacific Power & Light Company is a public utility subject to the jurisdiction of the Oregon Public Utility Commission.

2. An affiliated interest relationship exists between Pacific Power, and Light Company and Trapper Mining, Inc.

This application appears fair and reasonable and not contrary to the public interest.

94-1550

Mike Kane
October 5, 1994
Page Four

STAFF RECOMMENDATION:

Therefore, based upon the discussion and conclusion noted above, I recommend approval of the application of Pacific Power & Light Company to enter into agreements for accounting purposes effective April, 1992 with Trapper Mining, Inc., for fuel and final reclamation services, and shareholder funding subject to the following conditions:

1. PP&L shall provide staff access to all books of account, as well as all documents, data, and records of PP&L and PP&L's affiliated interests which pertain to the transaction(s) between PP&L and its affiliated interest, Trapper.

2. The Commission reserves the right to review for reasonableness all financial aspects of this arrangement in any subsequent rate proceeding or earnings review under an alternative form of regulation.

3. PP&L shall notify the Commission in advance of any substantive changes to the agreement, including any material changes in any cost. Any changes to the agreement terms which alter the intent and extent of activities under the agreement from those approved herein shall be submitted for approval in an application for supplemental order (or their appropriate format) in this docket.

4. For accounting purposes, the return component used in calculating PP&L's Oregon cost of services received from Trapper shall be limited to PP&L's current Oregon-authorized overall rate of return, effective April, 1992.

5. PP&L shall promptly notify the Commission with full details of any capital funding necessary under the Shareholder Funding Agreement.

TPR/1311HH

cc: Bill Warren
Administrative Hearings Division

CASE: UE 207
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Exhibits in Support of
Reply Testimony

July 14, 2009

STAFF EXHIBIT 205

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 09-113. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 207 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CERTIFICATE OF SERVICE

UE 207

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 14th day of July, 2009.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
550 Capitol St NE Ste 215
Salem, Oregon 97301-2551
Telephone: (503) 378-5763

UE 207
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