CASE: UE 207
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 300

Surrebuttal Testimony

August 25, 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. ARE YOU THE SAME KELCEY BROWN THAT FILED REPLY TESTIMONY IN THIS PROCEEDING?

A. Yes. My Witness Qualification Statement can be found in Exhibit Staff/101, Brown/1.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. This testimony is to respond to PacifiCorp's rebuttal testimony filed on August 11, 2008.

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

A. Staff continues to recommends the following adjustments (on an Oregon allocated basis) to PacifiCorp's requested net variable power cost (NVPC) increase of $20.0 Million.[1]

1. A reduction of $5,499,515 to NVPC associated with PacifiCorp's Coal Fuel Burn Expense.

[1] *See* PPL/104, Duvall/3, Line 12.

2. A reduction of $2,415,901 to NVPC due to increased generation at the Bear Creek, Tokatee, and JC Boyle hydro facilities associated with normalized forecasting.
3. A reduction of $327,294 to NVPC due to continued generation at the Condit hydro plant during October through December 2010.

4. Additionally, I support the ICNU adjustments associated with minimum loading and deration, and GRID market caps. Mr. Falkenberg calculated these adjustments as $1,081,846 and $4,709,314 respectively.

These adjustments total $14,052,065 on an Oregon allocated basis. I also continue to recommend that the Company pursue a modification of its Open Access Transmission Tariff with the Federal Energy Regulatory Commission (FERC) to pursue recovery of wind integration costs from non-owned wind facilities. Finally, Staff continues to recommend that the Commission require PacifiCorp to update annually its “Other Revenue” account for those items that have a direct relation to variable power costs.

Q. DO YOU WISH TO INTRODUCE STAFF WITNESS MICHAEL DOUGHERTY’S SURREBUTTAL TESTIMONY?

A. Yes. Staff witness Michael Dougherty provides testimony continuing to support an adjustment to PacifiCorp’s fuel burn expense in Staff/400.

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

A. In Staff/400, Staff witness Dougherty continues to support his lower of cost or market methodology for the Jim Bridger and Huntington coal plants. Staff's adjustment has increased by a small amount, as compared to reply testimony, due to PacifiCorp's August 2010 TAM update. Overall, Mr. Dougherty recommends a $20,461,866 system-wide ($5,499,515 – Oregon allocated) reduction in PacifiCorp's coal fuel burn expense.

Q. DO YOU HAVE ANY GENERAL CONCERNS ABOUT THE COMPANY'S TOTAL NET POWER COST (NPC) REQUEST OF $1,095 MILLION?

A. Yes. In its rebuttal testimony PacifiCorp claims that Mr. Falkenberg's calculation of NVPC at $995 million is too low. The Company cites actual NVPC for the 12 months ending May 2009 at $1,055 million, and the current level of NVPC in rates at $1,042 million. [2] However, the Company failed to cite its recent filing in Utah for $999 million in NVPC for the time period of July 2009 through June 2010.The Utah filed NVPC is 10 percent lower than the requested NVPC in Oregon with only a 6 month difference in test periods.[3] Combining actual power costs through June 2009 and PacifiCorp's forecast of power costs through December 2009 from its Utah filing results in NVPC of $982 million for end-of-year 2009. This is 12 percent lower than the current Company request in Oregon.

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[2] See PPL/104, Duvall/3, Lines 18-21.
[3] Staff requests that, pursuant to OAR 860-04-0050, the Commission take official notice of the Utah filing, which is publicly available at:
http://www.psc.state.ut.us/utilities/electric/elecindx/elecindx/0903523indx.html

Q. WHAT ARE SOME SPECIFIC DIFFERENCES BETWEEN THE UTAH FILING AND THE OREGON FILING WHICH RESULTS IN THE UTAH FILING BEING SO MUCH LOWER?

A. The Utah filing realizes higher revenue in wholesale sales ($74 million), lower power purchase costs ($25 million), lower coal costs ($47 million), higher gas costs ($31 million), and higher wind integration costs ($21 million) with almost no change in demand.[4] Surprisingly, these differences are consistent for the overlapping period between the two filings of January 2010 through June 2010. In fact, when looking at the exact same time period, the Utah filing is $25 million lower than the Oregon filing on a total company basis.

Q. DOES STAFF PROPOSE AN ADJUSTMENT ASSOCIATED WITH THE DIFFERENCE BETWEEN THE COMPANY'S FILINGS IN OREGON AND UTAH?

A. No. Staff only became aware of the Utah filing very recently and has not had an opportunity to fully analyze the differences in NVPC. Staff only notes the Utah filing in rebuttal testimony to counter the Company's claims that ICNU's NVPC recommendation is too low.

Hydro Adjustment

Q. PLEASE SUMMARIZE STAFF'S HYDRO ADJUSTMENT.

A. In rebuttal testimony, Staff proposed adjustments to the output of the J.C. Boyle, Tokatee, and Bear River hydro facilities. The adjustments are needed

[4] See Exhibit Staff/303, Brown/1-20.

to correct for the Company's deviation from standard hydro normalization practice by including short term adjustments and a "smoothing factor" to reduce variability in its hydro modeling.

Q. IN GENERAL, WHAT ISSUES DOES THE COMPANY RAISE ABOUT STAFF'S PROPOSED ADJUSTMENT?

A. The Company claims that Staff's adjustment is unfounded, incorrectly uses UE 199 levels of hydro production, and is incorrectly calculated.

Q. HOW DO YOU RESPOND TO THESE ISSUES?

A. The Company claims that Staff incorrectly used UE 199 as a basis for setting what hydro levels should have been in test year 2010. However, in Staff data request No. 86 Staff asked the Company to provide the output of the GRID model using the prior methodology and the Company responded that it had not performed this analysis.[5] The Company states it has made a change in modeling, which includes a smoothing factor, re-calculation of historic inflows and short term adjustments for drought. Staff has no ability to isolate the effect of each of these changes in methodology. Using the most recent information available from UE 199 is a reasonable assumption given the Company's refusal to perform the requested analysis.

Q. HAVE YOU RECALCULATED YOUR MONETARY ADJUSTMENT ASSOCIATED WITH THE CHANGE IN HYDRO?

[5] See Exhibit Staff/302, Brown/1.

A. Yes. Using the GRID model's "Hydro Market Value" worksheet, Staff calculated the market value in $/MWh for each hydro unit for the 2010 test year. Staff then used this to calculate its proposed monetary adjustment.

Q. DID THE COMPANY MAKE AN ADJUSTMENT TO THE MODELING OF THE BEAR RIVER SYSTEM BASED ON THE ASSUMPTION OF CONTINUED DROUGHT CONDITIONS?

A. Yes. The Company claims that the recent adjustment to the Bear River system is due to the Company recognizing an operational constraint imposed by a government entity.[6] However, this agreement was entered into in 1958. Staff agrees that there are operational constraints that the Company must adhere to, but these operational constraints are unchanged from UE 199. The operational constraints that the Company refers to are associated with the weather, and have nothing to do with a requirement on the Company to release additional or less water as compared to prior years. The Company has taken it upon itself to make a short term modeling adjustment based on forecasted weather conditions.

Q. THE COMPANY CITES OPERATIONAL CONSTRAINTS FOR THE FORESEEABLE FUTURE AS ITS REASON FOR ADJUSTING THE FORECAST AT BEAR RIVER. IS THIS CONSISTENT WITH ITS RESPONSE TO STAFF DATA REQUESTS?

A. No. In Staff data request No. 60 the Company stated that the reason that the Bear River system experienced a significant decline in production in the test

[6] See PPL/104, Duvall/17, Lines 2-19.

period was due to the region currently being impacted by drought conditions. Therefore, the Company excluded flood control years from the forecast for the next three years, and then, according to the Company, the flood control years will be added back.[7] The Company did not cite its recognition of operational constraints.

Q. DO YOU CONTINUE TO SUPPORT YOUR ADJUSTMENTS TO THE J.C. BOYLE AND TOKATEE FACILITIES?

A. Yes. The J.C. Boyle and Tokatee hydro facilities have realized significant changes in generation from the prior filing with no discernable reason for this significant decline. As stated in my reply testimony, the J.C. Boyle facility has realized up and down swings for the last two filings and the Tokatee facility has realized a significant drop over the past two periods. The Tokatee facility long term average, based on actual production, shows significantly higher levels of generation than what is modeled in the current filing.

Q. HAS THE COMPANY REFUTED THE STAFF ADJUSTMENT FOR THESE TWO HYDRO FACILITIES OR PROVIDED A RATIONALE FOR SWINGS IN MODELLED OPERATIONS?

A. No. The Company states that there could be any number of reasons for the differences in normalized hydro generation.[8] The Company has not provided a credible reason for changes in the normalized generation of these two facilities.

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[7] See Exhibit Staff/103, Brown/8.
[8] See PPL/104, Duvall/16, Lines 10-13.

Q. IN YOUR REVIEW OF THE COMPANY'S NORMALIZED HYDRO GENERATION DID YOU NOTICE ANY SIGNFICANT CHANGES IN FACILITIES THAT ARE NOT INCLUDED IN YOUR ADJUSTMENT?

A. Yes. For example, the Prospect facility shows an overall 15 percent decline, or 47,000 MWh drop over the prior period. When looking at the time period of 2008 versus 2009, the Prospect facility declined by only 2.5 percent, or a drop of only 8,000 MWh. Using the "engineering" worksheet that PacifiCorp references in its testimony[9], and investigation of the FERC hydropower relicensing website, Staff was able to verify that PacifiCorp was granted a new license for the Prospect facility on April 8, 2008. According to the PacifiCorp "engineering" worksheet, bypass flow requirements were part of the new licensing agreement and would begin to be implemented in late 2008, which explains the significant decline over the prior period. PacifiCorp has not provided any specific reasons for the changes in the Tokatee or J.C. Boyle facilities and therefore has not met its burden of proof that these changes are reasonable.

Q. PLEASE DISCUSS THE CONDIT HYDRO FACILITY'S CONTINUED OPERATION.

A. For the last four years PacifiCorp has forecast that the Condit hydro facility would discontinue operation in October of the test year. However, this facility has continued to operate every year for the full twelve month period. The Company has once again renewed its operating license for the Condit facility

[9] See PPL/104, Duvall/14, Lines 9-14.

for the test year 2010 through October. The history of the facility demonstrates that the Company is unable to accurately forecast the decommissioning of the Condit facility, and the facility should, therefore, be modeled for the full twelve month period based upon the historic operation of the facility.

Q. IN ITS REBUTTAL DID THE COMPANY CITE ANY NEW INFORMATION THAT WOULD PROVIDE ADDITIONAL ASSURANCE THAT THE CONDIT FACILITY WILL BE DECOMMISSIONED IN OCTOBER 2010?

A. No. To the contrary, the Company states that it has not yet received all the necessary permits for it to begin decommissioning.[10]

Q. THE COMPANY CLAIMS THAT ADJUSTING THE CONDIT FACILITY TO OPERATE FOR THE FULL TWELVE MONTH PERIOD IS INCONSISTENT WITH THE COMMISSION'S KNOWN AND MEASURABLE STANDARD, DO YOU AGREE?

A. No. In fact, it is the known and measurable standard that should require modeling the Condit facility as continuing to operate for the full twelve months of 2010. There is no basis to conclude that the decommissioning of Condit by October 2010 is a known and measurable event. The Company has shown over the past four years that it is unable to reasonably predict the occurrence of this decommissioning, and concedes that the necessary permits have not been acquired. Therefore, Staff recommends that the Condit facility be modeled to operate through December 2010.

[10] See PPL/104, Duvall/9, Lines 8-9.

Long Hollow Wind Facility

Q. DO YOU CONTINUE TO RECOMMEND THAT THE COMPANY PURSUE A MODIFICATION OF ITS OPEN ACCESS TRANSMISSION TARIFF AT FERC IN ORDER TO RECOVER WIND INTEGRATION COSTS FROM NON-OWNED WIND FACILITIES?

A. Yes. However, the Company explained in its rebuttal filing that it is currently monitoring, and participating where appropriate, in the FERC study on reliable integration of wind energy into the transmission system. The Company anticipates that it may include a wind integration tariff in its next FERC rate case, which is scheduled to be filed on or before June 2011.[11] Therefore, Staff recommends that PacifiCorp provide an update to the Commission in 2010 on the status of FERC's study on wind integration and its likely impact on Oregon customers. Additionally, Staff recommends that the Company commit to notify the Commission once it reaches a decision on whether or not to include a wind integration tariff prior to filing its next FERC rate case.

Other Revenue

Q. DO YOU CONTINUE TO RECOMMEND THAT THE COMMISSION REQUIRE THE COMPANY TO UPDATE ITS "OTHER REVENUE" ACCOUNT IN NON-GENERAL RATE CASE YEARS?

A. Yes. In non-general rate case years the TAM filing updates NVPC but fails to update matching revenues included in the "Other Revenue" account. In UE

[11] See PPL/104, Duvall/44.

199, I argued that revenues should be updated for facilities or services, such as the Little Mountain steam sales, whose costs are directly updated in the TAM. The failure to update both costs and revenues in an annual power cost filing is a regulatory asymmetry that the Commission corrected in PGE's last general rate case.[12]

Q. IS STAFF ATTEMPTING TO "EXPAND A PRIOR AGREEMENT" OR WIDEN "THE SCOPE OF THE TAM UNILATERALLY"?

A. No. The Company claims that Staff agreed in the TAM guidelines to "explicitly" include only the steam revenues associated with Little Mountain in stand-alone TAM filings. However, a close reading of the UE 199 agreement indicates that the Company agreed to update Little Mountain steam sales revenue in stand-alone TAM filings. The UE 199 agreement does not explicitly prevent Staff from proposing additional "Other Revenue" accounts that are appropriate to update.

Q. PLEASE COMMENT ON THE COMPANY'S STATEMENT THAT UPDATING OTHER REVENUES IN STAND-ALONE TAM YEARS IS INCONSISTENT WITH THE STAFF RECOMMENDATION THAT O&M COSTS SHOULD NOT BE INCLUDED IN THE TAM FILING.

A. Staff recommended that O&M costs not be included in the TAM filing because they are already included in base rates and this would constitute double recovery. In addition, the revenue associated with the operation of natural gas-

[12] See Order No. 07-015 at Page 19.

fired facilities is already accounted for in the TAM in the Sales for Resale account.

Q. PLEASE COMMENT ON THE COMPANY'S STATEMENT THAT UPDATING OTHER REVENUES IS INCONSISTENT WITH THE STAFF RECOMMENDATION TO INCLUDE THE DISPATCH BENEFITS OF NEW RESOURCES IN THE ANNUAL TAM EVEN IF THE FIXED COSTS OF THE NEW RESOURCES ARE NOT YET IN RATES.

A. In UE 210 Staff recommended that the Company continue to honor its agreement in the original TAM filing and include the dispatch benefits of a resource, even if the Company had not chosen to file for the inclusion of the fixed costs of the resource at that time. This recommendation is not inconsistent with the recommendation that PacifiCorp also be required to update its Other Revenue account in a stand-alone test year. On the contrary, it is consistent with this recommendation, in that customers are not currently able to realize the dispatch benefit of the resource or the recognition of other revenues until the Company chooses to file a general rate case.

ICNU Adjustments

Q. PLEASE SUMMARIZE ICNU'S ADJUSTMENTS ASSOCIATED WITH MARKET CAPS.

A. The effect of market caps is that it limits the amount of economic thermal generation that runs during certain hours (1:00 A.M. to 5:00 A.M.) so that the volume of sales established by the caps will not be exceeded. These were originally implemented because PacifiCorp argued that without the caps, GRID would allow coal units to generate more than could actually be sold in the market.

Q. DOES MR. FALKENBERG BELIEVE THAT THIS SITUATION IN THE MARKET CURRENTLY EXISTS?

A. No. According to recent actual sales data during the graveyard shift, sales were in excess of 4.6 million MWh, as compared to the GRID model run of 2.0 million MWh without the caps in place.[13]

Q DID THE COMPANY REFUTE MR. FALKENBERG'S RECENT SALES DATA, AND THE FACT THAT IT SHOWS SIGNIFICANTLY HIGHER SALES ON AN ACTUAL BASIS THAN THAT MODELED IN GRID?

A. No. The Company did not refute this information and instead argued that the four-year average of coal generation, from the time period of 2005-2008, was lower than the modeled GRID generation with the removal of the market caps.

Q. IS IT REASONABLE TO COMPARE THE GRID RESULTS WITH A FOUR-YEAR AVERAGE OF COAL GENERATION, UNADJUSTED FOR LOAD GROWTH OR ANY OTHER SIGNIFICANT FACTOR?

A. No. A more relevant comparison of the reasonableness of coal generation is to look at a more recent time period. In response to Staff data request No. 80 the Company provided the actual coal generation of 46,018,093 MWh for the period of July 2007 through June 2008, as compared to the GRID modeled

[13] See ICNU/100, Falkenberg/13, Lines 9-13.

coal generation in 2010 of 45,698,110 MWh.[14] This comparison clearly shows that the GRID model underestimates actual generation as compared to more recent time periods.

Q. PLEASE DISCUSS ICNU'S MINIMUM OPERATING CAPACITY AND HEAT RATE CURVE ADJUSTMENTS.

A. Mr. Falkenberg proposes two adjustments. First, he proposes to adjust the minimum operating capacity of plants to account for equivalent forced outage rates. Second, he proposed to adjust the modeled heat rate curves of plants to account for the plant's derated capacity due to equivalent forced outages. I sponsored Staff's testimony on these issues in Docket No. UM 1355. Staff continues to support these adjustments for the same reason provided in my testimony in UM 1355. Staff requests that the Commission take official notice, pursuant to OAR 860-014-0050, of my testimony filed in UM 1355 regarding the adjustment of the minimum operating capacity and the heat rate curve of a facility (See: Docket UM 1355, Staff/300, Brown/18-20).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[14] See Exhibit Staff/302, Brown/3.

Oregon
Theodore R. Kulongoski, Governor

Public Utility Commission
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August 25, 2009

Via Electronic Filing and U.S. Mail

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

RE: **<u>Docket No. UE 207</u> – 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 Redacted Surrebuttal Testimony.

/s/ Kay Barnes
Kay Barnes
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
(503) 378-5763
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c: UE 207 Service List (parties)

CASE: UE 207
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Exhibits in Support of Surrebuttal Testimony

August 25, 2009

UE-207/PacifiCorp
August 20, 2009
OPUC Data Request 86

OPUC Data Request 86

Using the most recently updated GRID model (August update) please provide the Hydro generation that would have been produced in the 2010 test year, if the prior hydro input hydro generation model had been used. Please discuss any significant changes from the current model results to the results using the prior method.

Response to OPUC Data Request 86

The Company has not prepared the normalized hydro generation using three exceedence levels for the test period in the current proceeding.

UE-207/PacifiCorp
August 20, 2009
OPUC Data Request 80

OPUC Data Request 80

Please provide the results of comparing the 12 month period of July 2007 to June 2008 of actual coal generation to the forecasted 2010 coal generation with and without market caps in GRID. If your results differ from your conclusion using your original analysis of a four-year comparison, please discuss.

Response to OPUC Data Request 80

For the 12-month period July 2007 to June 2008, please refer to the workpaper named "Historical vs. Normalized Coal Generation.xls" filed concurrently with the Company's rebuttal testimony. For the forecast 2010 coal generation with market caps, please refer to the workpaper named "_OR 2010 TAM August with Adoptions (GOLD) _2009 08 06.xls" also filed concurrently with the Company's rebuttal testimony. For convenience, the Company's forecast 2010 coal generation and the actual coal generation in the 12-month period of July 2007 to June 2008 are provided as Attachment OPUC 80. The Company has not performed a study without the market caps in GRID.

Please refer to non-confidential Attachment OPUC 80 on the enclosed CD.

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Coal Generation: OR 2010 TAM August with Adoptions (GOLD) _2009 08 06.xls													
Carbon	1,188,418	111,011	97,723	107,134	106,883	97,729	98,020	104,558	105,099	100,151	93,092	58,840	108,180
Cholla	2,873,922	256,058	229,102	131,607	247,929	249,898	242,678	256,363	257,680	248,090	256,659	244,387	253,472
Colstrip	1,157,417	101,684	91,932	101,856	98,548	101,684	98,548	101,770	101,770	77,254	81,969	98,548	101,856
Craig	1,357,993	116,857	105,589	107,534	105,586	116,424	112,843	116,795	116,875	112,886	116,581	113,092	116,933
Dave Johnston	5,897,343	514,145	464,705	514,699	498,073	510,672	494,710	510,977	510,977	463,764	401,791	498,073	514,757
Hayden	633,786	55,396	50,030	36,997	53,601	55,396	53,601	55,391	55,391	53,601	55,396	53,601	55,386
Hunter	8,042,046	724,728	646,557	526,117	647,893	674,214	649,897	697,805	702,686	674,955	687,284	687,920	721,989
Huntington	6,656,495	588,126	529,228	584,636	341,097	565,603	558,722	586,208	592,507	571,194	580,558	569,816	588,798
Jim Bridger	10,294,306	913,290	824,286	880,503	661,104	685,646	885,565	917,292	917,376	888,041	917,007	887,996	916,201
Naughton	5,392,539	471,698	424,055	469,211	337,269	441,159	454,832	470,143	470,348	454,858	469,907	456,966	472,092
Wyodak	2,203,844	195,393	177,228	196,149	189,159	193,991	185,879	187,092	187,793	185,879	163,332	145,642	196,309
Total Coal Generation	45,698,110	4,048,384	3,640,435	3,656,442	3,287,143	3,692,416	3,835,295	4,004,393	4,018,501	3,830,672	3,823,575	3,814,880	4,045,974

July 2007 - June 2008	7/07 - 6/08	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08
Actual Coal Generation													
Carbon	1,213,467	116,512	120,034	91,824	118,843	110,715	119,498	117,518	107,516	37,917	59,377	109,671	104,042
Cholla	2,466,042	254,695	256,744	211,397	252,120	252,593	255,252	253,825	242,258	234,597	(607)	62,445	190,723
Colstrip	1,229,285	109,494	93,206	106,112	106,532	98,009	100,439	109,566	102,098	108,786	100,627	102,206	92,210
Craig	1,342,945	108,264	115,528	109,919	115,104	115,657	117,252	113,407	112,622	121,897	80,413	117,267	115,615
Dave Johnston	5,708,547	509,280	485,641	438,851	482,884	499,448	478,307	526,536	496,591	441,254	482,992	427,583	439,180
Hayden	629,800	57,380	50,594	50,137	57,646	55,159	58,016	57,897	51,240	57,639	34,914	46,358	52,820
Hunter	8,706,602	763,249	759,477	735,717	753,275	681,567	767,823	756,173	606,607	780,690	768,530	715,038	618,456
Huntington	7,055,820	653,683	567,353	599,785	613,151	525,704	598,592	654,187	469,000	626,762	587,441	593,193	566,969
Jim Bridger	10,123,449	885,692	956,666	858,829	889,655	939,780	933,169	917,481	891,698	895,961	671,546	650,175	632,797
Naughton	5,288,077	466,321	469,115	455,994	453,186	415,205	458,649	476,794	414,166	471,074	337,834	437,257	432,482
Wyodak	2,254,059	190,327	193,820	184,103	194,826	166,835	200,096	178,508	175,029	194,637	191,548	189,401	194,929
Total Coal Generation	46,018,093	4,114,897	4,068,178	3,842,668	4,037,222	3,860,672	4,087,093	4,154,161	4,107,473	3,881,994	4,076,578	3,900,059	4,126,510

CASE: UE 207
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support of
Surrebuttal Testimony

August 25, 2009

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
Special Sales For Resale						
Long Term Firm Sales						
Black Hills	$12,010,268	$12,068,850	($58,582)	$5,961,850	$6,004,870	($43,020)
BPA Wind	$2,748,457	$2,757,326	($8,869)	$1,501,505	$1,501,505	$0
East Area Sales (WCA Sale)	$0	$0	$0	$0	$0	$0
Hurricane Sale	$985,499	$985,499	$0	$492,750	$492,750	$0
LADWP (IPP Layoff)	$25,490,589	$25,490,589	$0	$12,640,538	$12,640,538	$0
PSCO	$32,536,058	$40,881,315	($8,345,257)	$15,797,903	$16,606,546	($808,643)
Salt River Project	$0	$3,572,067	($3,572,067)	$0	$0	$0
Sierra Pac 2	$0	$0	$0	$0	$0	$0
SMUD	$12,964,800	$12,898,200	$66,600	$2,216,300	$6,870,900	($4,654,600)
UAMPS s223863	$0	$0	$0	$0	$0	$0
UAMPS s404236	$0	$293,760	($293,760)	$0	$0	$0
UMPA II	$9,769,272	$9,697,740	$71,532	$3,925,095	$3,925,095	$0
Total Long Term Firm Sales	$96,504,943	$108,645,346	($12,140,402)	$42,535,940	$48,042,203	($5,506,263)
Short Term Firm Sales						
COB	$68,026,380	$46,698,480	$21,327,900	$40,129,280	$40,129,280	$0
Colorado	$0	$0	$0	$0	$0	$0
Four Corners	$22,386,220	$45,321,540	($22,935,320)	$12,139,440	$12,139,440	$0
Idaho	$0	$5,358,240	($5,358,240)	$0	$0	$0
Mid Columbia	$18,520,800	$42,586,200	($24,065,400)	$16,226,200	$16,226,200	$0
Mona	$0	$14,628,000	($14,628,000)	$0	$0	$0
Palo Verde	$65,690,490	$144,925,690	($79,235,200)	$41,743,290	$41,743,290	$0
SP15	$0	$14,054,400	($14,054,400)	$0	$0	$0
Utah	$0	$0	$0	$0	$0	$0
Washington	$0	$0	$0	$0	$0	$0
West Main	$0	$0	$0	$0	$0	$0
Wyoming	$0	$0	$0	$0	$0	$0
STF Index Trades	$19,895,525		$19,895,525	$11,743,494	$0	$11,743,494
STF Trading Margin	$4,782,179	$15,484,506	($10,702,327)	$2,391,089	$9,966,620	($7,575,530)
Total Short Term Firm Sales	$199,301,594	$329,057,056	($129,755,463)	$124,372,793	$120,204,830	$4,167,964
System Balancing Sales						
COB	$74,453,281	$76,772,606	($2,319,326)	$33,403,936	$28,541,262	$4,862,674
Four Corners	$141,499,635	$114,649,925	$26,849,710	$62,665,075	$60,945,505	$1,719,570
Mid Columbia	$95,596,444	$84,534,330	$11,062,114	$16,954,013	$29,380,743	($12,426,730)
Mona	$17,180,121	$14,156,265	$3,023,856	$7,778,066	$7,055,496	$722,570
Palo Verde	$65,586,532	$35,971,801	$29,614,732	$26,022,487	$29,182,703	($3,160,217)
SP15	$0	$0	$0	$0	$0	$0
Trapped Energy	$0	$0	$0	$0	$0	$0
Total System Balancing Sales	$394,316,013	$326,084,927	$68,231,086	$146,823,576	$155,105,710	($8,282,134)
Total Special Sales For Resale	**$690,122,550**	**$763,787,329**	**($73,664,779)**	**$313,732,310**	**$323,352,742**	**($9,620,433)**

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
Purchased Power & Net Interchange						
Long Term Firm Purchases			$0	$0	$0	$0
APS Supplemental	$9,756,544	$8,898,252	$858,291	$7,091,277	$3,016,352	$4,074,925
Avoided Cost Resource	$0	$0	$0	$0	$0	$0
Blanding Purchase	$19,725	$19,725	$0	$9,781	$9,781	$0
Chehalis Tolling	$0	$0	$0	$0	$0	$0
Combine Hills	$3,911,516	$3,892,240	$19,275	$1,979,462	$1,979,462	$0
Constellation p257677	$0	$0	$0	$0	$0	$0
Constellation p257678	$0	$0	$0	$0	$0	$0
Constellation p268849	$0	$0	$0	$0	$0	$0
Deseret Purchase	$32,249,754	$31,825,629	$424,125	$16,066,269	$16,066,269	$0
Douglas PUD Settlement	$1,894,200	$1,677,034	$217,166	$1,035,388	$1,100,746	($65,358)
Gemstate	$2,716,400	$2,716,400	$0	$1,311,300	$1,311,300	$0
Georgia-Pacific Camas	$7,280,700	$6,377,764	$902,936	$3,610,430	$3,187,922	$422,508
Grant County 10 aMW purchase	$6,971,139	$5,802,716	$1,168,423	$3,262,748	$2,608,858	$653,889
Hermiston Purchase	$92,817,337	$93,420,755	($603,419)	$40,136,865	$43,766,985	($3,630,120)
Hurricane Purchase	$328,501	$328,501	$0	$164,250	$164,250	$0
Idaho Power P278538	$777,066	$598,062	$179,003	$228,777	$216,472	$12,305
IPP Purchase	$25,490,589	$25,490,589	$0	$12,640,538	$12,640,538	$0
Kennecott Generation Incentive	$8,211,540	$9,663,109	($1,451,569)	$1,750,579	$3,400,003	($1,649,424)
LADWP 491303-4	$1,161,570	$199,840	$961,730	$199,840	$199,840	$0
MagCorp	$0	$0	$0	$0	$0	$0
MagCorp Reserves	$1,755,360	$1,755,360	$0	$877,680	$877,680	$0
Morgan Stanley p189046	$10,683,600	$10,683,600	$0	$5,324,400	$5,324,400	$0
Morgan Stanley p272153-6-8	$1,485,000	$1,505,000	($20,000)	$495,000	$495,000	$0
Morgan Stanley p272154-7	$1,572,000	$524,000	$1,048,000	$524,000	$524,000	$0
Nebo Heat Rate Option	$0	$0	$0	$0	$0	$0
Nucor	$4,610,400	$4,610,400	$0	$2,305,200	$2,305,200	$0
P4 Production	$16,193,520	$15,804,720	$388,800	$8,096,760	$8,096,760	$0
PGE Cove	$252,000	$252,000	$0	$126,000	$126,000	$0
Rock River	$5,041,688	$5,041,688	$0	$2,620,885	$2,620,885	$0
Roseburg Forest Products	$8,767,111	$8,767,111	$0	$4,350,173	$4,350,173	$0
Small Purchases east	$570,556	$568,781	$1,774	$284,328	$267,117	$17,211
Small Purchases west	$0	$0	$0	$0	$0	$0
Three Buttes Wind	$10,935,525	$1,183,705	$9,751,820	$1,183,705	$1,183,705	$0
Tri-State Purchase	$11,267,375	$12,074,562	($807,188)	$5,430,159	$5,870,346	($440,187)
Weyerhaeuser Reserve	$0	$145,800	($145,800)	$0	$0	$0
Wolverine Creek	$9,748,726	$9,707,058	$41,668	$5,417,046	$5,417,046	$0
DSM (Irrigation)	$0	$0	$0	$0	$0	$0
Long Term Firm Purchases Total	$276,469,441	$263,534,404	$12,935,037	$126,522,840	$127,127,091	($604,251)
Seasonal Purchased Power						
Morgan Stanley p244840	$0	$5,282,160	($5,282,160)	$0	$0	$0
Morgan Stanley p244841	$0	$1,744,080	($1,744,080)	$0	$0	$0
UBS p268848	$0	$0	$0	$0	$0	$0
UBS p268850	$0	$441,500	($441,500)	$0	$0	$0
Seasonal Purchased Power Total	$0	$7,467,740	($7,467,740)	$0	$0	$0

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
Qualifying Facilities			$0	$0	$0	$0
QF California	$4,026,592	$4,000,672	$25,920	$3,377,341	$3,377,401	($60)
QF Idaho	$4,477,649	$4,124,745	$352,903	$2,355,779	$2,205,180	$150,599
QF Oregon	$19,440,841	$18,924,589	$516,252	$11,176,611	$11,014,757	$161,853
QF Utah	$705,089	$899,012	($193,922)	$375,360	$352,030	$23,330
QF Washington	$1,931,867	$2,342,974	($411,107)	$980,775	$1,094,737	($113,961)
QF Wyoming	$725,034	$708,320	$16,714	$302,835	$302,823	$11
Biomass	$27,250,062	$26,718,017	$532,045	$13,526,193	$13,390,482	$135,711
Chevron Wind QF	$2,365,482	$0	$2,365,482	$1,076,174	$0	$1,076,174
Co-Gen II	$0		$0	$0		$0
Douglas County Forest Products QF	$203,637	$304,150	($100,513)	$169,509	$159,680	$9,829
D.R. Johnson	$0		$0	$0	$0	$0
Evergreen BioPower QF	$3,571,338	$3,404,832	$166,506	$1,773,944	$1,773,944	$0
ExxonMobil QF	$31,569,800	$31,560,145	$9,656	$16,170,536	$16,170,536	$0
Kennecott QF	$0	$6,080,182	($6,080,182)	$0	$0	$0
Mountain Wind 1 QF	$8,431,084	$8,430,074	$1,010	$4,202,336	$4,202,336	$0
Mountain Wind 2 QF	$12,198,479	$12,196,126	$2,353	$6,297,312	$6,297,312	$0
Oregon Wind Farm QF	$10,337,165	$7,115,281	$3,221,884	$5,381,495	$3,714,103	$1,667,392
Simplot Phosphates	$3,796,797	$3,749,133	$47,664	$1,885,232	$1,885,232	$0
Spanish Fork Wind 2 QF	$2,948,260	$2,748,100	$200,160	$1,173,492	$1,113,007	$60,485
Sunnyside	$24,652,043	$23,672,887	$979,156	$11,823,608	$11,736,161	$87,447
Tesoro QF	$0	$6,787,443	($6,787,443)	$0	$0	$0
US Magnesium QF	$0	$2,788,477	($2,788,477)	$0	$0	$0
Weyerhaeuser QF	$0	$10,876,057	($10,876,057)	$0	$0	$0
			$0	$0	$0	$0
Qualifying Facilities Total	$158,631,218	$177,431,216	($18,799,998)	$82,048,530	$78,789,720	$3,258,810
Mid-Columbia Contracts						
Canadian Entitlement	$0	$0	$0	$0	$0	$0
Chelan - Rocky Reach	$4,240,725	$4,188,220	$52,506	$2,120,363	$2,105,564	$14,798
Douglas - Wells	$4,812,738	$4,542,540	$270,199	$2,398,759	$2,434,753	($35,994)
Grant Displacement	$12,134,859	$12,298,312	($163,452)	$5,878,221	$5,936,634	($58,413)
Grant Reasonable	($14,406,120)	($14,646,429)	$240,309	($7,203,060)	($7,053,205)	($149,855)
Grant Meaningful Priority	$0	$0	$0	$0	$0	$0
Grant Surplus	$1,790,608	$2,191,931	($401,323)	$895,304	$895,304	$0
Grant - Priest Rapids	$0	$0	$0	$0	$0	$0
Grant - Wanapum	$0	$4,645,080	($4,645,080)	$0	$0	$0
Mid-Columbia Contracts Total	$8,572,811	$13,219,652	($4,646,841)	$4,089,586	$4,319,050	($229,464)
Total Long Term Firm Purchases	$443,673,470	$461,653,012	($17,979,542)	$212,660,956	$210,235,861	$2,425,095

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
Storage & Exchange			$0	$0	$0	$0
APGI/Colockum Capacity Exchange	$0	$0	$0	$0	$0	$0
APS Exchange	$0	$0	$0	$0	$0	$0
Black Hills CTs	$1,411,140	$2,290,320	($879,180)	$698,580	$1,156,500	($457,920)
BPA Exchange	$0	$0	$0	$0	$0	$0
BPA FC II Storage Agreement	$0	$0	$0	$0	$0	$0
BPA FC IV Storage Agreement	$0	$0	$0	$0	$0	$0
BPA Peaking	$47,058,000	$47,058,000	$0	$23,529,000	$23,529,000	$0
BPA So. Idaho Exchange	$0	$0	$0	$0	$0	$0
Cowlitz Swift	$0	$0	$0	$0	$0	$0
EWEB FC I Storage Agreement	$0	$0	$0	$0	$0	$0
PSCo Exchange	$3,600,000	$2,700,000	$900,000	$1,800,000	$1,800,000	$0
PSCO FC III Storage Agreement	$0	$0	$0	$0	$0	$0
Redding Exchange	$0	$0	$0	$0	$0	$0
SCL State Line Storage Agreement	$0	$0	$0	$0	$0	$0
TransAlta p371343/s371344	($1,644,000)	($1,644,000)	$0	($540,000)	($540,000)	$0
Tri-State Exchange	$0	$0	$0	$0	$0	$0
Total Storage & Exchange	$50,425,140	$50,404,320	$20,820	$25,487,580	$25,945,500	($457,920)
Short Term Firm Purchases						
COB	$1,634,300	$1,634,300	$0	$1,634,300	$1,634,300	$0
Colorado	$0	$0	$0	$0	$0	$0
Four Corners	$0	$4,017,000	($4,017,000)	$0	$0	$0
Idaho	$0	$0	$0	$0	$0	$0
Mid Columbia	$36,615,272	$55,135,308	($18,520,036)	$0	$0	$0
Mona	$0	$8,747,200	($8,747,200)	$0	$0	$0
Palo Verde	$10,329,900	$25,679,300	($15,349,400)	$4,478,100	$4,478,100	$0
SP15	$0	$0	$0	$0	$0	$0
Utah	$0	$0	$0	$0	$0	$0
Washington	$0	$0	$0	$0	$0	$0
West Main	$0	$0	$0	$0	$0	$0
Wyoming	$0	$0	$0	$0	$0	$0
STF Electric Swaps	($115,269,391)	($187,752,494)	$72,483,103	($77,470,265)	($82,348,266)	$4,878,001
STF Index Trades	$0	$1,519,945	($1,519,945)	$0	$0	$0
Total Short Term Firm Purchases	($66,689,919)	($91,019,441)	$24,329,522	($71,357,865)	($76,235,866)	$4,878,001
System Balancing Purchases						
COB	$9,556,200	$3,946,669	$5,609,531	$3,356,782	$2,604,642	$752,140
Four Corners	$18,303,439	$14,288,476	$4,014,963	$10,211,996	$8,847,382	$1,364,614
Mid Columbia	$35,446,900	$21,117,581	$14,329,319	$25,323,981	$16,739,638	$8,584,343
Mona	$20,709,681	$12,682,974	$8,026,707	$7,965,304	$7,744,033	$221,271
Palo Verde	$4,580,471	$18,233,410	($13,652,939)	$3,467,766	$2,866,278	$601,487
SP15	$0	$17,588	($17,588)	$0	$0	$0
Emergency Purchases	$199,732	$161,914	$37,818	$199,732	$161,914	$37,818
Total System Balancing Purchases	$88,796,424	$70,448,612	$18,347,812	$50,525,560	$38,963,887	$11,561,672
Total Purchased Power & Net Intercl	$516,205,115	$491,486,503	$24,718,612	$217,316,231	$198,909,383	$18,406,848

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
Wheeling & U. of F. Expense			$0	$0	$0	$0
Firm Wheeling	$144,294,464	$140,897,457	$3,397,007	$72,804,038	$73,259,570	($455,532)
ST Firm & Non-Firm	$274,921	$952,117	($677,196)	$92,778	$410,678	($317,900)
Total Wheeling & U. of F. Expense	$144,569,385	$141,849,574	$2,719,811	$72,896,816	$73,670,248	($773,432)
Coal Fuel Burn Expense						
Carbon	$20,059,572	$19,120,765	$938,807	$10,433,023	$10,225,308	$207,715
Cholla	$55,207,439	$54,384,462	$822,978	$26,075,408	$26,348,346	($272,938)
Colstrip	$12,944,264	$11,907,943	$1,036,321	$6,645,979	$6,113,818	$532,161
Craig	$20,838,403	$19,589,117	$1,249,285	$10,201,767	$9,675,458	$526,309
Dave Johnston	$52,577,538	$52,178,639	$398,899	$26,718,775	$26,684,806	$33,969
Hayden	$11,288,166	$11,469,930	($181,764)	$5,432,997	$5,520,841	($87,844)
Hunter	$112,775,720	$107,289,793	$5,485,927	$54,263,936	$53,178,291	$1,085,645
Huntington	$96,648,088	$76,034,135	$20,613,953	$45,989,741	$36,758,402	$9,231,339
Jim Bridger	$181,504,009	$168,435,956	$13,068,052	$85,533,072	$79,401,434	$6,131,638
Naughton	$81,873,772	$79,192,952	$2,680,820	$39,443,691	$38,221,241	$1,222,450
			$0	$0	$0	$0
Wyodak	$20,144,777	$19,411,986	$732,791	$10,394,826	$10,003,615	$391,211
Total Coal Fuel Burn Expense	$665,861,747	$619,015,678	$46,846,069	$321,133,214	$302,131,560	$19,001,654
Gas Fuel Burn Expense						
Chehalis	$69,548,930	$53,155,990	$16,392,940	$6,627,676	$12,660,035	($6,032,359)
Currant Creek	$79,283,790	$60,537,903	$18,745,887	$35,709,141	$29,937,433	$5,771,707
Gadsby	$6,297,743	$4,859,768	$1,437,975	$0	$282,872	($282,872)
Gadsby CT	$9,220,013	$5,654,519	$3,565,494	$2,266,809	$1,742,181	$524,627
Hermiston	$56,036,843	$56,783,207	($746,364)	$21,910,609	$25,455,786	($3,545,177)
Lake Side	$101,444,269	$85,692,649	$15,751,620	$45,582,121	$45,376,582	$205,540
Little Mountain	$7,510,350	$5,873,470	$1,636,880	$4,300,318	$3,868,343	$431,975
West Valley	$0	$0	$0	$0	$0	$0
Total Gas Fuel Burn	$329,341,938	$272,557,507	$56,784,431	$116,396,674	$119,323,232	($2,926,559)
Gas Physical	($45,851)	($492,814)	$446,963	($40,450)	($69,592)	$29,142
Gas Swaps	$81,087,189	$174,152,653	($93,065,464)	$43,865,244	$51,488,753	($7,623,509)
Clay Basin Gas Storage	($1,275,691)	($1,130,387)	($145,304)	($1,206,158)	($955,171)	($250,987)
Pipeline Reservation Fees	$26,474,459	$26,976,411	($501,952)	$13,203,054	$13,407,736	($204,682)
Additional Fixed Costs	$12,123,654	$6,331,298	$5,792,356	$5,020,266	$4,191,647	$828,619
Total Gas Fuel Burn Expense	$447,705,697	$478,394,667	($30,688,970)	$177,238,630	$187,386,605	($10,147,975)
Other Generation						
Blundell	$3,498,000	$3,897,089	($399,089)	$1,809,039	$2,029,657	($220,618)
Foote Creek I	$0	$0	$0	$0	$0	$0
Glenrock Wind	$0	$0	$0	$0	$0	$0
Glenrock III Wind	$0	$0	$0	$0	$0	$0
Goodnoe Wind	$0	$0	$0	$0	$0	$0
High Plains Wind	$0	$0	$0	$0	$0	$0
Leaning Juniper 1	$0	$0	$0	$0	$0	$0
Marengo I	$0	$0	$0	$0	$0	$0
Marengo II	$0	$0	$0	$0	$0	$0
McFadden Ridge Wind	$0	$0	$0	$0	$0	$0
Rolling Hills Wind	$0	$0	$0	$0	$0	$0
Seven Mile Wind	$0	$0	$0	$0	$0	$0
Seven Mile II Wind	$0	$0	$0	$0	$0	$0
Wind Integration Charge	$7,682,475	$28,287,667	($20,605,192)	$3,877,017	$14,854,029	($10,977,013)
Total Other Generation	$11,180,475	$32,184,756	($21,004,281)	$5,686,056	$16,883,686	($11,197,630)
Net Power Cost	$1,095,399,869	$999,143,849	$96,256,020	$480,538,637	$455,628,739	$24,909,898

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
MWh's						
Adjustments to Load						
Bridger Loss Placement	-	-	-	-	-	0
BPA Hermiston Losses	-	-	-	-	-	0
DSM Cool Keeper	-	-	-	-	-	0
DSM (Irrigation)	-	-	-	-	-	0
Lewis River Hydro Losses	-	86,997	(86,997)	-	47,614	(47,614)
MagCorp Curtailment	(38,516)	(38,522)	6	(12,506)	(12,506)	0
Monsanto Curtailment	(42,790)	(42,790)	(0)	(2,504)	(2,504)	0
Station Service	70,811	69,706	1,105	34,993	34,911	82
			-	-		0
Total Adjustments to Load	(10,495)	75,391	(85,887)	19,983	67,516	(47,533)
System Load	58,674,332	58,168,989	505,343	28,542,520	28,542,520	0
Net System Load	58,663,837	58,244,381	419,457	28,562,503	28,610,036	(47,533)
Special Sales For Resale						
Long Term Firm Sales			-	-		0
Black Hills	362,468	362,609	(141)	178,554	179,474	(921)
BPA Wind	39,096	39,096	-	21,359	21,359	0
East Area Sales (WCA Sale)	-	-	-	-	-	0
Hurricane Sale	13,140	13,140	-	6,570	6,570	0
LADWP (IPP Layoff)	613,200	613,200	-	304,080	304,080	0
PSCO	464,766	584,225	(119,459)	223,252	238,958	(15,705)
Salt River Project	-	110,400	(110,400)	-	-	0
Sierra Pac 2	-	-	-	-	-	0
SMUD	350,400	348,600	1,800	59,900	185,700	(125,800)
UAMPS s223863	-	-	-	-	-	0
UAMPS s404236	-	7,344	(7,344)	-	-	0
UMPA II	223,878	220,898	2,981	89,468	89,468	0
Total Long Term Firm Sales	2,066,948	2,299,512	(232,564)	883,182	1,025,608	(142,426)
Short Term Firm Sales			-	-		
COB	857,200	598,000	259,200	518,400	518,400	0
Colorado	-	-	-	-	-	0
Four Corners	408,200	608,200	(200,000)	213,000	213,000	0
Idaho	-	97,600	(97,600)	-	-	0
Mid Columbia	268,000	624,800	(356,800)	237,200	237,200	0
Mona	-	245,200	(245,200)	-	-	0
Palo Verde	1,606,800	2,879,200	(1,272,400)	994,400	994,400	0
SP15	-	244,000	(244,000)	-	-	0
Utah	-	-	-	-	-	0
Washington	-	-	-	-	-	0
West Main	-	-	-	-	-	0
Wyoming	-	-	-	-	-	0
STF Trading Margin	-	-	-	-	-	0
			-	-		0
Total Short Term Firm Sales	3,140,200	5,297,000	(2,156,800)	1,963,000	1,963,000	0

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
			-	-	-	0
System Balancing Sales			-	-	-	0
COB	1,514,223	1,871,722	(357,499)	751,652	680,248	71,404
Four Corners	2,811,532	2,948,565	(137,032)	1,403,357	1,496,054	(92,697)
Mid Columbia	1,837,691	2,159,879	(322,188)	382,107	676,806	(294,699)
Mona	341,343	347,219	(5,876)	169,703	164,306	5,397
Palo Verde	1,275,119	863,947	411,173	546,891	664,644	(117,753)
SP15	-	-	-	-	-	0
Trapped Energy	-	-	-	-	-	0
Total System Balancing Sales	7,779,909	8,191,332	(411,423)	3,253,710	3,682,059	(428,349)
Total Special Sales For Resale	12,987,057	15,787,844	(2,800,787)	6,099,892	6,670,667	(570,775)
Total Requirements	71,650,894	74,032,224	(2,381,330)	34,662,395	35,280,703	(618,308)
Purchased Power & Net Interchange						
Long Term Firm Purchases						
APS Supplemental	222,750	231,400	(8,650)	178,900	68,400	110,500
Avoided Cost Resource	-	-	-	-	-	0
Blanding Purchase	263	263	-	130	130	0
Chehalis Tolling	-	-	-	-	-	0
Combine Hills	111,503	111,503	-	56,427	56,427	0
Constellation p257677	-	-	-	-	-	0
Constellation p257678	-	-	-	-	-	0
Constellation p268849	-	-	-	-	-	0
Deseret Purchase	785,772	785,772	-	389,657	389,657	0
Douglas PUD Settlement	68,696	62,824	5,872	37,646	40,270	(2,625)
Gemstate	37,448	45,176	(7,728)	11,613	18,093	(6,480)
Georgia-Pacific Camas	97,741	86,302	11,439	48,469	42,796	5,672
Grant County 10 aMW purchase	87,634	87,634	-	43,968	43,968	0
Hermiston Purchase	1,568,132	1,672,420	(104,287)	579,924	716,938	(137,014)
Hurricane Purchase	4,380	4,380	-	2,190	2,190	0
Idaho Power P278538	15,765	15,765	(0)	5,668	5,668	0
IPP Purchase	613,200	613,200	-	304,080	304,080	0
Kennecott Generation Incentive	-	-	-	-	-	0
LADWP 491303-4	23,250	4,000	19,250	4,000	4,000	0
MagCorp	-	-	-	-	-	0
MagCorp Reserves	-	-	-	-	-	0
Morgan Stanley p189046	245,600	245,600	-	122,400	122,400	0
Morgan Stanley p272153-6-8	-	-	-	-	-	0
Morgan Stanley p272154-7	-	-	-	-	-	0
Nebo Heat Rate Option	-	-	-	-	-	0
Nucor	-	-	-	-	-	0
P4 Production	-	-	-	-	-	0
PGE Cove	12,000	12,000	-	5,964	5,964	0
Rock River	142,099	142,099	-	73,869	73,869	0
Roseburg Forest Products	153,792	153,792	-	76,264	76,264	0
Small Purchases east	8,636	8,098	538	3,525	3,832	(307)
Small Purchases west	-	-	-	-	-	0
Three Buttes Wind	171,403	18,553	152,850	18,553	18,553	0
Tri-State Purchase	170,819	183,376	(12,558)	76,637	95,610	(18,974)
Weyerhaeuser Reserve	-	-	-	-	-	0
Wolverine Creek	176,896	176,896	-	98,295	98,295	0
			-	-	-	0
Long Term Firm Purchases Total	4,717,779	4,661,053	56,726	2,138,179	2,187,406	(49,227)

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
			-	-	-	0
Seasonal Purchased Power			-	-	-	0
Morgan Stanley p244840	-	62,400	(62,400)	-	-	0
Morgan Stanley p244841	-	20,800	(20,800)	-	-	0
UBS p268848	-	-	-	-	-	0
UBS p268850	-	-	-	-	-	0
			-	-	-	0
Seasonal Purchased Power Total	-	83,200	(83,200)	-	-	0
			-	-	-	0
Qualifying Facilities			-	-	-	0
QF California	34,066	33,980	86	28,757	-	28,757
QF Idaho	80,665	76,373	4,292	42,772	28,758	14,014
QF Oregon	229,067	224,627	4,440	130,480	40,796	89,684
QF Utah	13,466	17,185	(3,719)	7,146	127,467	(120,321)
QF Washington	13,136	20,282	(7,146)	6,682	6,591	91
QF Wyoming	11,387	11,390	(3)	4,663	8,554	(3,891)
Biomass	173,449	171,477	1,972	86,012	4,663	81,349
Chevron Wind QF	44,528		44,528	22,492	85,034	(62,542)
Co-Gen II	-	-	-	-	-	0
Douglas County Forest Products QF	5,071	8,424	(3,352)	4,365	4,365	0
D.R. Johnson	-	-	-	-	-	0
Evergreen BioPower QF	67,072	67,072	-	33,278	33,278	0
ExxonMobil QF	648,960	648,960	-	347,136	347,136	0
Kennecott QF	-	80,956	(80,956)	-	-	0
Mountain Wind 1 QF	151,796	151,796	-	77,562	77,562	0
Mountain Wind 2 QF	189,638	189,638	-	101,904	101,904	0
Oregon Wind Farm QF	161,172	111,235	49,937	83,623	57,713	25,909
Simplot Phosphates	74,460	74,460	-	36,924	36,924	0
Spanish Fork Wind 2 QF	55,562	51,422	4,139	23,417	21,939	1,478
Sunnyside	385,060	385,060	-	186,933	186,933	0
Tesoro QF	-	91,290	(91,290)	-	-	0
US Magnesium QF	-	88,320	(88,320)	-	-	0
Weyerhaeuser QF	-	167,076	(167,076)	-	-	0
			-	-	-	0
Qualifying Facilities Total	2,338,555	2,671,022	(332,467)	1,224,146	1,169,617	54,528
			-	-	-	0
Mid-Columbia Contracts			-	-	-	0
Canadian Entitlement	(17,528)	(17,228)	(300)	(8,680)	(8,531)	(149)
Chelan - Rocky Reach	327,226	326,788	438	181,505	181,481	24
Douglas - Wells	252,519	252,523	(3)	141,115	141,099	17
Grant Displacement	439,837	440,689	(852)	233,851	233,851	0
Grant Reasonable	-	-	-	-	-	0
Grant Meaningful Priority	-	-	-	-	-	0
Grant Surplus	88,890	351,167	(262,277)	49,094	46,461	2,632
			-	-	-	0
Grant - Priest Rapids	-	-	-	-	-	0
Grant - Wanapum	-	-	-	-	-	0
			-	-	-	0
Mid-Columbia Contracts Total	1,090,944	1,353,938	(262,994)	596,885	594,361	2,524
			-	-	-	0
Total Long Term Firm Purchases	8,147,277	8,769,213	(621,936)	3,959,210	3,951,384	7,826

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
			-	-	-	0
Storage & Exchange			-	-	-	0
APGI/Colockum Capacity Exchange	(268,153)	(268,153)	-	(102,562)	(102,562)	0
APS Exchange	450	445	5	(4,445)	(4,545)	100
Black Hills CTs	-	-	-	-	-	0
BPA Exchange	0	0	(0)	83,333	83,333	0
BPA FC II Storage Agreement	239	239	-	(123)	(123)	0
BPA FC IV Storage Agreement	2,229	2,229	-	(1,151)	(1,151)	0
BPA Peaking	0	2,401	(2,401)	(11,555)	(4,540)	(7,015)
BPA So. Idaho Exchange	39,670	39,607	63	19,799	19,799	0
Cowlitz Swift	6,534	(14,898)	21,432	2,917	(8,357)	11,274
EWEB FC I Storage Agreement	1,235	1,235	-	266	266	0
PSCo Exchange	-	-	-	-	-	0
PSCO FC III Storage Agreement	(0)	(0)	-	(8,153)	(8,153)	0
Redding Exchange	(55)	(316)	261	30,028	32,409	(2,381)
SCL State Line Storage Agreement	14,486	14,486	-	14,898	14,898	0
TransAlta p371343/s371344	-	-	-	-	-	0
Tri-State Exchange	-	-	-	-	-	0
			-	-	-	0
Total Storage & Exchange	(203,365)	(222,725)	19,360	23,252	21,273	1,978
			-	-	-	0
Short Term Firm Purchases			-	-	-	0
COB	23,600	23,600	-	23,600	23,600	0
Colorado	-	-	-	-	-	0
Four Corners	-	31,200	(31,200)	-	-	0
Idaho	-	-	-	-	-	0
Mid Columbia	485,200	757,920	(272,720)	-	-	0
Mona	-	123,200	(123,200)	-	-	0
Palo Verde	249,800	497,000	(247,200)	108,600	108,600	0
SP15	-	48,800	(48,800)	-	-	0
Utah	-	-	-	-	-	0
Washington	-	-	-	-	-	0
West Main	-	-	-	-	-	0
Wyoming	-	-	-	-	-	0
STF Index Trades	-	-	-	-	-	0
			-	-	-	0
Total Short Term Firm Purchases	758,600	1,481,720	(723,120)	132,200	132,200	0
			-	-	-	0
System Balancing Purchases			-	-	-	0
COB	196,284	123,212	73,073	92,603	90,626	1,977
Four Corners	486,408	481,865	4,543	302,506	288,735	13,771
Mid Columbia	960,991	746,113	214,878	738,607	612,001	126,606
Mona	447,353	368,871	78,482	218,432	230,014	(11,583)
Palo Verde	124,182	616,055	(491,873)	94,414	84,394	10,020
SP15	-	625	(625)	-	-	0
Emergency Purchases	4,729	4,162	567	4,729	4,162	567
			-	-	-	0
Total System Balancing Purchases	2,219,947	2,340,902	(120,955)	1,451,290	1,309,931	141,359
			-	-	-	0
Total Purchased Power & Net Intercl	10,922,460	12,369,110	(1,446,651)	5,565,952	5,414,789	151,163

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
			-	-	-	0
Coal Generation			-	-	-	0
Carbon	1,188,418	1,154,544	33,874	618,499	620,615	(2,116)
Cholla	2,873,922	2,841,633	32,290	1,357,272	1,377,508	(20,235)
Colstrip	1,157,417	1,167,661	(10,245)	594,251	599,499	(5,248)
Craig	1,357,993	1,333,737	24,257	664,832	658,984	5,848
Dave Johnston	5,897,343	5,880,435	16,908	2,997,004	3,007,642	(10,638)
Hayden	633,786	634,289	(503)	305,020	305,273	(253)
Hunter	8,042,046	7,864,611	177,435	3,869,406	3,907,499	(38,093)
Huntington	6,656,495	6,648,682	7,813	3,167,413	3,216,647	(49,234)
Jim Bridger	10,294,306	10,310,080	(15,774)	4,850,394	4,860,019	(9,625)
Naughton	5,392,539	5,370,784	21,755	2,598,225	2,592,545	5,680
			-	-	-	0
Wyodak	2,203,844	2,136,096	67,748	1,137,798	1,101,277	36,522
			-	-	-	0
Total Coal Generation	45,698,110	45,342,552	355,558	22,160,115	22,247,508	(87,393)
			-	-	-	0
Gas Generation			-	-	-	0
Chehalis	1,607,195	1,645,019	(37,824)	145,347	284,496	(139,150)
Currant Creek	2,044,347	2,171,053	(126,707)	944,548	850,298	94,250
Gadsby	96,696	125,701	(29,005)	-	4,822	(4,822)
Gadsby CT	126,469	119,905	6,563	29,150	24,730	4,420
Hermiston	1,568,132	1,672,420	(104,287)	579,924	716,938	(137,014)
Lake Side	2,760,047	3,282,227	(522,181)	1,276,846	1,430,157	(153,311)
Little Mountain	83,357	81,578	1,778	49,775	49,004	771
			-	-	-	0
West Valley	-	-	-	-	-	0
			-	-	-	0
Total Gas Generation	8,286,241	9,097,903	(811,662)	3,025,590	3,360,445	(334,855)
			-	-	-	0
Hydro Generation			-	-	-	0
West Hydro	3,727,038	3,879,539	(152,501)	2,331,081	2,452,078	(120,997)
East Hydro	308,123	355,019	(46,896)	167,923	206,282	(38,359)
			-	-	-	0
Total Hydro Generation	4,035,162	4,234,558	(199,396)	2,499,003	2,658,360	(159,356)

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	[redacted]	Oregon January through June	Utah January through June	Change Oregon - Utah
			-		-	-	0
Other Generation			-		-		0
Blundell	181,827	173,899	7,928		94,034	91,016	3,018
Blundell Bottoming Cycle	86,961	86,961	(0)		44,973	44,844	129
			-		-	-	0
Total Blundell	268,787	260,860	7,927		139,007	135,859	3,148
			-		-	-	0
Foote Creek I	102,699	102,699	-		54,583	54,583	0
Glenrock Wind	332,471	323,799	8,672		168,162	163,861	4,301
Glenrock III Wind	124,409	124,409	-		62,953	62,953	0
Goodnoe Wind	266,887	266,887	-		138,467	138,467	0
High Plains Wind	309,370	243,996	65,374		164,600	164,600	0
Leaning Juniper 1	305,473	305,473	-		152,583	152,583	0
Marengo I	393,136	393,136	-		203,574	203,574	0
Marengo II	187,226	187,226	-		105,947	105,947	0
McFadden Ridge Wind	-	68,561	(68,561)		-	46,757	(46,757)
Rolling Hills Wind	-	292,594	(292,594)		-	148,557	(148,557)
Seven Mile Wind	349,596	349,596	-		185,347	185,347	0
Seven Mile II Wind	68,862	68,862	-		36,509	36,509	0
			-		-	-	0
Total Wind Generation	2,440,129	2,727,238	(287,109)		1,272,725	1,463,739	(191,014)
			-		-	-	0
Total Other Generation	2,708,917	2,988,098	(279,181)		1,411,732	1,599,599	(187,866)
					-	-	
Total Resources	71,650,889	74,032,222	(2,381,333)		34,662,393	35,280,700	(618,308)

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
Fuel Burned (MMBtu)						
Carbon	13,707,576	13,339,702	367,874	7,129,337	7,133,739	(4,402)
Cholla	31,062,195	30,817,844	244,351	14,671,189	14,930,716	(259,526)
Colstrip	12,493,832	12,552,257	(58,425)	6,414,713	6,444,624	(29,911)
Craig	13,720,601	13,472,140	248,461	6,717,136	6,654,161	62,975
Dave Johnston	65,560,713	65,756,789	(196,076)	33,316,536	33,628,826	(312,290)
Hayden	6,708,726	6,801,818	(93,092)	3,228,911	3,273,931	(45,020)
Hunter	85,290,013	83,758,848	1,531,165	41,038,714	41,515,151	(476,437)
Huntington	66,687,515	66,058,127	629,388	31,733,073	31,935,539	(202,466)
Jim Bridger	107,557,665	107,539,722	17,944	50,686,151	50,694,701	(8,550)
Naughton	56,269,979	56,187,144	82,835	27,108,745	27,117,857	(9,112)
Wyodak	26,460,995	26,211,787	249,209	13,654,027	13,507,754	146,274
Chehalis	11,492,394	11,835,342	(342,948)	1,041,235	2,059,053	(1,017,818)
Currant Creek	15,075,127	16,191,863	(1,116,735)	7,002,999	6,493,392	509,607
Gadsby	1,178,755	1,548,908	(370,153)	-	62,882	(62,882)
Gadsby CT	1,683,545	1,600,894	82,652	421,116	356,378	64,738
Hermiston	11,308,218	12,107,105	(798,887)	4,176,860	5,193,173	(1,016,313)
Lake Side	19,147,811	22,468,282	(3,320,472)	8,871,255	9,806,385	(935,130)
Little Mountain	1,362,832	1,340,170	22,662	812,943	803,092	9,851
West Valley	-	-	-		-	0
Burn Rate (MMBtu/MWh)						
Carbon	11.53	11.55	(0.02)	11.53	11.49	0
Cholla	10.81	10.85	(0.04)	10.81	10.84	(0)
Colstrip	10.79	10.75	0.04	10.79	10.75	0
Craig	10.10	10.10	0.00	10.10	10.10	0
Dave Johnston	11.12	11.18	(0.07)	11.12	11.18	(0)
Hayden	10.59	10.72	(0.14)	10.59	10.72	(0)
Hunter	10.61	10.65	(0.04)	10.61	10.62	(0)
Huntington	10.02	9.94	0.08	10.02	9.93	0
Jim Bridger	10.45	10.43	0.02	10.45	10.43	0
Naughton	10.43	10.46	(0.03)	10.43	10.46	(0)
Wyodak	12.01	12.27	(0.26)	12.00	12.27	(0)
Chehalis	7.15	7.19	(0.04)	7.16	7.24	(0)
Currant Creek	7.37	7.46	(0.08)	7.41	7.64	(0)
Gadsby	12.19	12.32	(0.13)	0.00	13.04	(13)
Gadsby CT	13.31	13.35	(0.04)	14.45	14.41	0
Hermiston	7.21	7.24	(0.03)	7.20	7.24	(0)
Lake Side	6.94	6.85	0.09	6.95	6.86	0
Little Mountain	16.35	16.43	(0.08)	16.33	16.39	(0)
West Valley	0.00	0.00	0.00	0.00	-	0

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
Average Fuel Cost ($/MMBtu)						0
Carbon	1.46	1.43	0.03	1.46	1.43	0
Cholla	1.78	1.76	0.01	1.78	1.76	0
Colstrip	1.04	0.95	0.09	1.04	0.95	0
Craig	1.52	1.45	0.06	1.52	1.45	0
Dave Johnston	0.80	0.79	0.01	0.80	0.79	0
Hayden	1.68	1.69	(0.00)	1.68	1.69	(0)
Hunter	1.32	1.28	0.04	1.32	1.28	0
Huntington	1.45	1.15	0.30	1.45	1.15	0
Jim Bridger	1.69	1.57	0.12	1.69	1.57	0
Naughton	1.46	1.41	0.05	1.46	1.41	0
			0.00			0
Wyodak	0.76	0.74	0.02	0.76	0.74	0
			0.00			0
Chehalis	5.93	5.01	0.91	5.81	4.98	1
Currant Creek	5.27	3.95	1.31	5.18	3.91	1
Gadsby	5.44	4.10	1.34	5.36	4.06	1
Gadsby CT	5.44	4.10	1.34	5.36	4.06	1
Hermiston	3.99	3.89	0.10	3.98	3.88	0
Lake Side	5.31	3.99	1.32	5.22	3.94	1
Little Mountain	5.44	4.10	1.34	5.36	4.06	1
West Valley	0.00	0.00	0.00	0.00		0
Peak Capacity (Nameplate)						
Blundell	23	23	-	23	23.00	0
Blundell Bottoming Cycle	11	11	-	10	10.00	0
			-			0
Carbon	172	172	-	172	172.00	0
Cholla	387	387	-	387	387.00	0
Colstrip	148	148	-	148	148.00	0
Craig	166	165	1	166	165.00	1
Dave Johnston	762	770	(8)	762	770.00	(8)
Hayden	78	78	-	78	78.00	0
Hunter	1,123	1,138	(15)	1,123	1,138.00	(15)
Huntington	895	895	-	895	895.00	0
Jim Bridger	1,413	1,419	(6)	1,413	1,419.32	(6)
Naughton	700	700	-	700	700.00	0
Wyodak	280	272	8	280	272.00	8
Chehalis	529	529	-	529	529.00	0
Currant Creek	549	584	(35)	549	584.00	(35)
Gadsby	231	231	-	231	230.50	0
Gadsby CT	123	125	(2)	123	124.50	(2)
Hermiston	248	496	(248)	248	496.00	(248)
Lake Side	584	584	-	584	584.00	0
Little Mountain	14	14	-	14	14.00	0
West Valley	-	-	-	-	-	0
			-			0

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
Capacity Factor			-			0
Blundell	90.2%	90.3%	(0.0%)	24.4%	0.24	(0)
Carbon	78.9%	76.6%	2.2%	21.4%	0.21	(0)
Cholla	84.8%	83.8%	1.0%	20.9%	0.21	(0)
Colstrip	89.3%	90.1%	(0.8%)	23.9%	0.24	(0)
Craig	93.7%	92.3%	1.4%	23.9%	0.24	0
Dave Johnston	88.6%	88.1%	0.5%	23.5%	0.24	0
Hayden	92.8%	92.8%	(0.1%)	23.3%	0.23	0
Hunter	81.8%	79.7%	2.1%	20.5%	0.21	(0)
Huntington	84.9%	84.8%	0.1%	21.1%	0.21	(0)
Jim Bridger	83.1%	83.2%	(0.1%)	20.5%	0.20	(0)
Naughton	88.3%	87.9%	0.4%	22.2%	0.22	0
Wyodak	91.1%	91.0%	0.1%	24.5%	0.24	0
Chehalis	35.5%	36.3%	(0.8%)	1.7%	0.03	(0)
Currant Creek	42.9%	44.5%	(1.6%)	10.4%	0.09	0
Gadsby	4.8%	6.2%	(1.4%)	-	0.00	(0)
Gadsby CT	11.9%	11.2%	0.7%	1.4%	0.01	0
Hermiston	74.4%	39.8%	34.5%	14.4%	0.09	0
Lake Side	55.1%	65.6%	(10.4%)	13.3%	0.15	(0)
Little Mountain	71.0%	71.7%	(0.7%)	22.1%	0.22	(0)
West Valley	-	-		-	-	0
Wind Integration Charge						
Foote Creek I	102,699	102,699	-	373,941	391,462	(17,521)
Glenrock Wind	332,471	323,799	8,672	1,221,098	1,229,626	(8,528)
Glenrock III Wind	124,409	124,409	-	456,703	472,434	(15,731)
High Plains Wind	309,370	243,996	65,374	1,134,651	908,121	226,530
Marengo I	393,136	393,136	-	1,472,598	1,474,182	(1,584)
Marengo II	187,226	187,226	-	704,209	706,089	(1,880)
McFadden Ridge Wind	-	68,561	(68,561)	-	256,373	(256,373)
Rolling Hills Wind	-	292,594	(292,594)	-	1,111,996	(1,111,996)
Seven Mile Wind	349,596	349,596	-	1,281,972	1,328,964	(46,992)
Seven Mile II Wind	68,862	68,862	-	252,518	261,774	(9,256)
			-			0
			-			0
			-			0
			-			0
Combine Hills	111,503	111,503	-	420,061	418,529	1,532
Rock River	142,099	142,099	-	516,198	542,389	(26,190)
Three Buttes Wind	171,403	18,553	152,850	578,807	37,107	541,700
Wolverine Creek	176,896	176,896	-	669,874	658,107	11,766
			-			0
BPA FC II Generation	5,650	5,650	-	10,596	10,977	(381)
BPA FC IV Generation	52,734	52,734	-	98,898	102,456	(3,558)
EWEB FC I Generation	27,563	27,563	-	51,692	53,551	(1,859)
PSCo FC III Generation	79,101	79,101	-	148,347	153,684	(5,336)
Long Hollow	333,438	336,971	(3,532)	624,603	628,011	(3,408)
State Line generation	491,423	481,633	9,790	947,499	926,251	21,249
--	-	-	-	-	-	0
			-			0
Chevron Wind QF	44,528		44,528	162,144		162,144
Mountain Wind 1 QF	151,796	151,796	-	552,784	582,823	(30,039)
Mountain Wind 2 QF	189,638	189,638	-	693,513	721,242	(27,729)
Oregon Wind Farm QF	161,172	111,235	49,937	621,027	407,468	213,559
Spanish Fork Wind 2 QF	55,562	51,422	4,139	206,670	192,622	14,048
Subtotal Wind Generation	4,062,274	4,091,671	(29,397)	13,200,403	13,576,238	(375,834)

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	[redacted]	Oregon January through June	Utah January through June	Change Oregon - Utah
			-				0
Generation subject to BPA Wind Integration Charges (included in wheeling)			-				0
Goodnoe Wind	266,887	266,887	-		1,018,263	986,680	31,583
Leaning Juniper 1	305,473	305,473	-		1,167,580	1,122,325	45,255
			-				0
Total Generation (MWh)	4,634,634	4,664,031	(29,397)		15,386,246	15,685,242	(298,996)
			0				0
Wind Integration Charge $/MWh			0				0
BPA Wind Integration Charge per kW-month			0.00				0
			0				0
Company Wind Integration Charge	4,671,615	28,287,667	(23,616,052)		15,180,464	93,858,995	(78,678,531)
Goodnoe Wind	1,455,120		1,455,120		2,788,980		2,788,980
Leaning Juniper 1	1,555,740		1,555,740		2,981,835		2,981,835
Total Wind Integration Charge ($)	7,682,475	28,287,667	(20,605,192)		20,951,279	93,858,995	(72,907,716)
Additional Fixed Costs							
Gadsby	496,359	353,352	143,007		992,718	706,705	286,013
Gadsby CT	226,355	114,673	111,681		409,663	213,119	196,545
			-				0
			-				0
			-				0
Chehalis	2,149,521	625,101	1,524,420		3,724,448	1,250,202	2,474,246
Additional O&M	-	-	-		-	-	0
Startup Fuel	2,149,521	625,101	1,524,420		3,724,448	1,250,202	2,474,246
Currant Creek	3,995,259	2,316,715	1,678,544		7,616,874	4,328,361	3,288,512
Additional O&M	-	-	-		-	-	0
Startup Fuel	3,995,259	2,316,715	1,678,544		7,616,874	4,328,361	3,288,512
Lake Side	5,256,160	2,921,456	2,334,704		9,986,908	5,413,947	4,572,961
Additional O&M	-	-	-		-	-	0
Startup Fuel	5,256,160	2,921,456	2,334,704		9,986,908	5,413,947	4,572,961
Total Fixed Costs	12,123,654	6,331,298	5,792,356		22,730,611	11,912,333	10,818,277

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
Special Sales For Resale						
Long Term Firm Sales						
Black Hills	33.13	33.28	(0.15)	33.39	33.46	(0.07)
BPA Wind	70.30	70.53	(0.23)	70.30	70.30	0.00
East Area Sales (WCA Sale)	-	-	-	-	-	0.00
Hurricane Sale	75.00	75.00	-	75.00	75.00	0.00
LADWP (IPP Layoff)	41.57	41.57	-	41.57	41.57	0.00
PSCO	70.01	69.98	0.03	70.76	69.50	1.27
Salt River Project	-	32.36	(32.36)	-	-	0.00
Sierra Pac 2	-	-	-	-	-	0.00
SMUD	37.00	37.00	-	37.00	37.00	0.00
UAMPS s223863	-	-	-	-	-	0.00
UAMPS s404236	-	40.00	(40.00)	-	-	0.00
UMPA II	43.64	43.90	(0.26)	43.87	43.87	0.00
Total Long Term Firm Sales	46.69	47.25	(0.56)	48.16	46.84	1.32
Short Term Firm Sales			-			0.00
COB	79.36	78.09	1.27	77.41	77.41	0.00
Colorado	-	-	-	-	-	0.00
Four Corners	54.84	74.52	(19.68)	56.99	56.99	0.00
Idaho	-	54.90	(54.90)	-	-	0.00
Mid Columbia	69.11	68.16	0.95	68.41	68.41	0.00
Mona	-	59.66	(59.66)	-	-	0.00
Palo Verde	40.88	50.34	(9.45)	41.98	41.98	0.00
SP15	-	57.60	(57.60)	-	-	0.00
Utah	-	-	-	-	-	0.00
Washington	-	-	-	-	-	0.00
West Main	-	-	-	-	-	0.00
Wyoming	-	-	-	-	-	0.00
STF Trading Margin	-	-	-	-	-	0.00
Total Short Term Firm Sales	63.47	62.12	1.35	63.36	61.24	2.12
System Balancing Sales			-			0.00
COB	49.17	41.02	8.15	44.44	41.96	2.48
Four Corners	50.33	38.88	11.44	44.65	40.74	3.92
Mid Columbia	52.02	39.14	12.88	44.37	43.41	0.96
Mona	50.33	40.77	9.56	45.83	42.94	2.89
Palo Verde	51.44	41.64	9.80	47.58	43.91	3.68
SP15	-	-	-	-	-	0.00
Trapped Energy	-	-	-	-	-	0.00
Total System Balancing Sales	50.68	39.81	10.88	45.12	42.12	3.00
Total Special Sales For Resale	53.14	48.38	4.76	51.43	48.47	2.96

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	[redacted]	Oregon January through June	Utah January through June	Change Oregon - Utah
Purchased Power & Net Interchange			-				***0.00***
Long Term Firm Purchases			-				***0.00***
APS Supplemental	43.80	38.45	5.35		39.64	44.10	(4.46)
Avoided Cost Resource	-	-	-		-	-	0.00
Blanding Purchase	75.00	75.00	-		75.00	75.00	0.00
Chehalis Tolling	-	-	-		-	-	0.00
Combine Hills	35.08	34.91	0.17		35.08	35.08	0.00
Constellation p257677	-	-	-		-	-	0.00
Constellation p257678	-	-	-		-	-	0.00
Constellation p268849	-	-	-		-	-	0.00
Deseret Purchase	41.04	40.50	0.54		41.23	41.23	0.00
Douglas PUD Settlement	27.57	26.69	0.88		27.50	27.33	0.17
Gemstate	72.54	60.13	12.41		112.92	72.48	40.44
Georgia-Pacific Camas	74.49	73.90	0.59		74.49	74.49	(0.00)
Grant County 10 aMW purchase	79.55	66.22	13.33		74.21	59.34	14.87
Hermiston Purchase	59.19	55.86	3.33		69.21	61.05	8.16
Hurricane Purchase	75.00	75.00	-		75.00	75.00	0.00
Idaho Power P278538	49.29	37.94	11.35		40.36	38.19	2.17
IPP Purchase	41.57	41.57	-		41.57	41.57	0.00
Kennecott Generation Incentive	-	-	-		-	-	0.00
LADWP 491303-4	49.96	49.96	-		49.96	49.96	0.00
MagCorp	-	-	-		-	-	0.00
MagCorp Reserves	-	-	-		-	-	0.00
Morgan Stanley p189046	43.50	43.50	-		43.50	43.50	0.00
Morgan Stanley p272153-6-8	-	-	-		-	-	0.00
Morgan Stanley p272154-7	-	-	-		-	-	0.00
Nebo Heat Rate Option	-	-	-		-	-	0.00
Nucor	-	-	-		-	-	0.00
P4 Production	-	-	-		-	-	0.00
PGE Cove	21.00	21.00	-		21.13	21.13	0.00
Rock River	35.48	35.48	-		35.48	35.48	0.00
Roseburg Forest Products	57.01	57.01	0.00		57.04	57.04	0.00
Small Purchases east	66.07	70.24	(4.17)		80.66	69.71	10.95
Small Purchases west	-	-	-		-	-	0.00
Three Buttes Wind	63.80	63.80	0.00		63.80	63.80	0.00
Tri-State Purchase	65.96	65.85	0.12		70.86	61.40	9.46
Weyerhaeuser Reserve	-	-	-		-	-	0.00
Wolverine Creek	55.11	54.87	0.24		55.11	55.11	0.00
Long Term Firm Purchases Total	58.60	56.54	2.06		59.17	58.12	1.06
Seasonal Purchased Power			-				0.00
Morgan Stanley p244840	-	84.65	(84.65)		-	-	0.00
Morgan Stanley p244841	-	83.85	(83.85)		-	-	0.00
UBS p268848	-	-	-		-	-	0.00
UBS p268850	-	-	-		-	-	0.00
Seasonal Purchased Power Total	-	89.76	(89.76)		-	-	0.00

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	[redacted]	Oregon January through June	Utah January through June	Change Oregon - Utah
Qualifying Facilities			-				0.00
QF California	118.20	117.74	0.46		117.44	117.44	0.00
QF Idaho	55.51	54.01	1.50		55.08	54.05	1.02
QF Oregon	84.87	84.25	0.62		85.66	86.41	(0.75)
QF Utah	52.36	52.31	0.05		52.53	53.41	(0.88)
QF Washington	147.06	115.52	31.54		146.79	127.98	18.81
QF Wyoming	63.67	62.19	1.48		64.94	64.94	0.00
Biomass	157.11	155.81	1.30		157.26	157.47	(0.21)
Co-Gen II	-	-	-		-	-	0.00
Douglas County Forest Products QF	40.15	36.11	4.05		38.83	36.58	2.25
D.R. Johnson	-	-	-		-	-	0.00
Evergreen BioPower QF	53.25	50.76	2.48		53.31	53.31	0.00
ExxonMobil QF	48.65	48.63	0.01		46.58	46.58	0.00
Kennecott QF	-	75.10	(75.10)		-	-	0.00
Mountain Wind 1 QF	55.54	55.54	0.01		54.18	54.18	0.00
Mountain Wind 2 QF	64.32	64.31	0.01		61.80	61.80	0.00
Oregon Wind Farm QF	64.14	63.97	0.17		64.35	64.35	0.00
Simplot Phosphates	50.99	50.35	0.64		51.06	51.06	0.00
Spanish Fork Wind 2 QF	53.06	53.44	(0.38)		50.11	50.73	(0.62)
Sunnyside	64.02	61.48	2.54		63.25	62.78	0.47
Tesoro QF	-	74.35	(74.35)		-	-	0.00
US Magnesium QF	-	31.57	(31.57)		-	-	0.00
Weyerhaeuser QF	-	65.10	(65.10)		-	-	0.00
Qualifying Facilities Total	67.83	66.43	1.40		67.03	67.36	(0.34)
Mid-Columbia Contracts			-				0.00
Canadian Entitlement	-	-	-		-	-	0.00
Chelan - Rocky Reach	12.96	12.82	0.14		11.68	11.60	0.08
Douglas - Wells	19.06	17.99	1.07		17.00	17.26	(0.26)
Grant Displacement	27.59	27.91	(0.32)		25.14	25.39	(0.25)
Grant Reasonable	-	-	-		-	-	0.00
Grant Meaningful Priority	-	-	-		-	-	0.00
Grant Surplus	20.14	6.24	13.90		18.24	19.27	(1.03)
Grant - Priest Rapids	-	-	-		-	-	0.00
Grant - Wanapum	-	-	-		-	-	0.00
Mid-Columbia Contracts Total	7.86	9.76	(1.91)		6.85	7.27	(0.42)
Total Long Term Firm Purchases			-				0.00
COB	69.25	69.25	-		69.25	69.25	0.00
Colorado	-	-	-		-	-	0.00
Four Corners	-	128.75	(128.75)		-	-	0.00
Idaho	-	-	-		-	-	0.00
Mid Columbia	75.46	72.75	2.72		-	-	0.00
Mona	-	71.00	(71.00)		-	-	0.00
Palo Verde	41.35	51.67	(10.32)		41.23	41.23	0.00
SP15	-	-	-		-	-	0.00
Utah	-	-	-		-	-	0.00
Washington	-	-	-		-	-	0.00
West Main	-	-	-		-	-	0.00
Wyoming	-	-	-		-	-	0.00
STF Index Trades	-	-	-		-	-	0.00
Total Short Term Firm Purchases	(87.91)	(61.43)	(26.48)		(539.77)	(576.67)	36.90

PacifiCorp Net Power Costs State Time period	Oregon 01/10-12/10	Utah 07/09-06/10	Change Oregon - Utah	Oregon January through June	Utah January through June	Change Oregon - Utah
System Balancing Purchases			-			0.00
COB	48.69	32.03	16.65	36.25	28.74	7.51
Four Corners	37.63	29.65	7.98	33.76	30.64	3.12
Mid Columbia	36.89	28.30	8.58	34.29	27.35	6.93
Mona	46.29	34.38	11.91	36.47	33.67	2.80
Palo Verde	36.88	29.60	7.29	36.73	33.96	2.77
SP15	-	28.14	(28.14)	-	-	0.00
Emergency Purchases	42.24	38.91	3.33	42.24	38.91	3.33
			-			0.00
Total System Balancing Purchases	40.00	30.09	9.90	34.81	29.74	5.07
Thermal Resources			-			0.00
Blundell	13.01	14.94	(1.93)	13.01	14.94	(1.93)
Carbon	16.88	16.56	0.32	16.87	16.48	0.39
Cholla	19.21	19.14	0.07	19.21	19.13	0.08
Colstrip	11.18	10.20	0.99	11.18	10.20	0.99
Craig	15.34	14.69	0.66	15.34	14.68	0.66
Dave Johnston	8.92	8.87	0.04	8.92	8.87	0.04
Hayden	17.81	18.08	(0.27)	17.81	18.08	(0.27)
Hunter	14.02	13.64	0.38	14.02	13.61	0.41
Huntington	14.52	11.44	3.08	14.52	11.43	3.09
Jim Bridger	17.63	16.34	1.29	17.63	16.34	1.30
Naughton	15.18	14.75	0.44	15.18	14.74	0.44
Wyodak	9.14	9.09	0.05	9.14	9.08	0.05
Total Coal Expenses	14.57	13.65	0.92	14.49	13.58	0.91
Chehalis	43.27	32.31	10.96	45.60	44.50	1.10
Currant Creek	38.78	27.88	10.90	37.81	35.21	2.60
Gadsby	65.13	38.66	26.47	-	58.66	(58.66)
Gadsby CT	72.90	47.16	25.75	77.76	70.45	7.31
Hermiston	35.73	33.95	1.78	37.78	35.51	2.28
Lake Side	36.75	26.11	10.65	35.70	31.73	3.97
Little Mountain	90.10	72.00	18.10	86.39	78.94	7.46
West Valley	-	-	-	-	-	0.00
Total Thermal Resources	54.03	52.58	1.45	58.58	55.76	2.82

CASE: UE 207
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Surrebuttal Testimony

<u>REDACTED VERSION</u>
August 25, 2009

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 400

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. ARE YOU THE SAME MICHAEL DOUGHERTY WHO PREVIOUSLY FILED REPLY TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to:

1. PacifiCorp's proposal for an accounting order concerning EITF 04-6 as described in PPL/201, Lasich/1-4;

2. PacifiCorp's rebuttal testimony concerning line item costs discussed in PPL/201, Lasich/4;

3. PacifiCorp's rebuttal testimony concerning Dave Johnston fuel burn expense as discussed in PPL/400, Morgan/2-4;

4. PacifiCorp's rebuttal testimony concerning Huntington fuel burn expense as discussed in PPL/400, Morgan/4-8;

5. PacifiCorp's Huntington fuel burn expense as reported in Utah (UT GRC NPC_June 2010 Gold_2009 95 29; and

6. PacifiCorp's rebuttal testimony concerning Bridger fuel burn expense as discussed in PPL/400, Morgan/9-15.

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 PacifiCorp's August - 2010 TAM Update.

Table 1 – Summary of Staff Adjustments

Plant	**PacifiCorp's August 2010 TAM Update**	**Staff**	**Adjustment**
Dave Johnston	$52,570,576	$52,075,269	$495,307
Huntington	$96,269,427	95,146,344	$1,123,083
Jim Bridger	$181,224,418	$162,380,942	$18,843,476
Total	**$330,064,421**	**$309,602,556**	**$20,461,865**
Total Oregon Adjustment Based on SG Factor			**$5,499,515**

Q. PLEASE SUMMARIZE THE UPDATES FROM YOUR REPLY TESTIMONY DATED JULY 14, 2009.

A. Dave Johnston plant – In its rebuttal testimony, PacifiCorp provides an updated price for the Open Position coal based on the average cost of two bids reported as $9.61 per ton, plus $0.25 per ton for dust suppression and side release, for a total cost of $9.86 per ton.[1] This actual cost is $0.72 lower than PacifiCorp's forecasted cost of $10.58/ton. Although the updated price is lower than the forecast price it is also higher than my escalated price of [redacted].[2] As a result, my adjustment is reduced from $930,622-system ($250,122-Oregon) to $495,307-system ($133,123-Oregon).[3]

Huntington and Jim Bridger plants – As mentioned in my July 14, 2009, reply testimony, I performed several lower of cost or market analyses pursuant to

[1] PPL/400, Morgan/3.
[2] Staff notes that the Staff recommended cost was closer to reality than PacifiCorp's forecasted cost.
[3] Included in Confidential Exhibit Staff 402.

Oregon Administrative Rule (OAR) 860-027-0048, *Allocation of Costs by an Energy Utility* for coal being supplied to these plants from affiliated mines. The lower of cost or market analyses results in a Huntington system-wide adjustment of $1,123,083 and a Jim Bridger system-wide adjustment of $18,212,080.[4] These adjustments differ from the adjustments in my reply testimony as a result of PacifiCorp's August - 2010 TAM Update.

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

A. Yes. However, because of PacifiCorp's August - 2010 TAM update, the recommended adjustments are actually greater than the amounts presented in my reply testimony. The underlying analyses supporting these alternate adjustments have not changed from the reply testimony.

Table 2 – Alternate Recommended Oregon Adjustments

Staff/200 Primary Adjustment	$5,499,515
First Alternate Adjustment	$5,329,815
Second Alternate Adjustment	$3,666,215

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared:

Exhibit Staff/401, consisting of 1 page;

Confidential Exhibit Staff/402, consisting of 5 pages;

Exhibit Staff/403, consisting of 8 pages; and

Confidential Exhibit Staff/404, consisting of 1 page.

[4] Included in Confidential Exhibit Staff 402.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

<u>Issue 1, EITF 04-6 Accounting Order</u>

Q. DO YOU AGREE THAT AN ACCOUNTING ORDER FOR EITF 04-6 IS NECESSARY?

A. No.

Q. PLEASE EXPLAIN.

A. Although EITF 04-06 requires mines to include stripping costs in the cost of coal that is extracted in a given year, the ***ratemaking*** standard for affiliated interest contracts is the lower of cost or market (LCM) pricing policy outlined in OAR 860-027-0048, *Allocation of Costs by an Energy Utility.* PacifiCorp claims in PPL/201, Lasich/3, that the magnitude of the disparity (resulting from EITF 04-6) will fluctuate based on the amount of coal extracted. However, what will not change is the LCM standard that affiliated pricing is determined by for ratemaking. The affiliate’s cost, no matter how costs are affected by EITF 04-6 (increased or decreased), should always be examined in comparison to market costs. As previously mentioned in my reply testimony, other mines must comply with this accounting pronouncement; and it is not a unique phenomenon to PacifiCorp.

Because the TAM is an annual filing, Staff will be able to perform analyses of the affiliated mines' cost and relationship to market on a yearly basis. Additionally, the affiliate's costs will be reviewed in context of the lower of cost or market (LCM) standard on an annual basis and there is no need for an additional regulatory asset balancing account. In any scenario of extracted compared to stripped, the affiliate's coal costs would still be the starting basis for Staff's recommendation[5]. As I state in my response to PacifiCorp Data Request No. 1.4, customers would only see a "benefit" of EITF 04-6 if PacifiCorp's costs are lower than market in "low cost years."

Q. DO YOU BELIEVE THAT AN ACCOUNTING ORDER IS NECESSARY TO REDUCE VOLATILITY OF COSTS?

A. No. As previously stated mentioned, Staff would continue to review the affiliate's costs on an annual basis. When Bridger Coal Company's costs are lower than market, Staff would use the lower cost as a basis for its adjustments. When BCC's costs are higher than market, Staff would use the market cost as a basis for its adjustments. Although PacifiCorp is concerned about asymmetrical cost recovery,[6] the nature of LCM is not symmetrical, and customers will always benefit from the lower of market or cost.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY CONCERNING EITF 04-6?

A. Yes.

[5] Staff's response to PacifiCorp's Data Request No. 1.4.
[6] *Ibid.*

ISSUE 2, MISCELLANEOUS LINE ITEM ADJUSTMENTS

Q. PLEASE EXPLAIN THE LINE ITEM ADJUSTMENTS YOU PRESENTED IN YOUR JULY 14, 2009, REPLY TESTIMONY.

A. As mentioned in my previous testimony, I reviewed 2008 line item costs concerning Bridger Coal Company (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 LCM analyses, I did not make these adjustments, as the LCM analyses 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 order to be consistent in methodology.

Q. DO YOU AGREE WITH PACIFICORP THAT YOU DID NOT PRESENT EMPIRICAL SUPPORT FOR THESE ADJUSTMENTS?

A. No. The adjustments were demonstrated in Confidential Exhibit Staff/203, Dougherty/5. The following supports the basis of the line item adjustments. It is important to note that I did not make these adjustments based on the LCM analyses.

<u>Wages and Salaries</u>

For management wages, I used PacifiCorp's 2008 actual amounts and escalated the amounts to 2010 using the CPI-U. I then subtracted the amounts from PacifiCorp's budget to receive the adjustment. This is consistent with previous Commission actions as increases in payroll from the historic base year should be tied to the rate of inflation using the All-Urban CPI. (Order 01-787 at 40; Order 99-697 at 43; Order 99-033 at 61; Order 95-322 at 10.) The management salary adjustment was $358,804 (Oregon) for Bridger and $357,619 (Oregon) for Energy West (Deer Creek). As previously stated, I did not make these adjustments based on the LCM analyses.

Management Overtime

The removal of management overtime is consistent with the Commission's treatment of manager overtime in Order No. 07-527 (UW 120), dated November 29, 2007.[7] The management overtime adjustment was $53,144 (Oregon) for Bridger and $72,022 (Oregon) for Energy West (Deer Creek). As previously stated, I did not make this adjustment based on the LCM analyses.

Bonuses

My proposed adjustment removed 50 percent of bonuses paid at Bridger and Energy West (Deer Creek). The Commission's policy is to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders) and disallow 50 percent of merit-based bonuses (because they equally benefit shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses. (Order 99-697 at 44-45; Order 99-033 at 62.) The bonus adjustment was $91,892 (Oregon) for Bridger and $180,957 (Oregon)

[7] As Staff notes, in most cases a General Manager position is salaried and the general manager would not earn overtime" Page 13. Included in Exhibit Staff/403.

for Energy West (Deer Creek). As previously stated, I did not make this adjustment based on the LCM analyses.

Fines and Citations

I removed $37,221 in fines and citation that were incurred at Bridger since these expenses should not be borne by customers. As previously stated, I did not make this adjustment based on the LCM analyses.

Meals and Entertainment

Staff routinely recommends a 50 / 50 sharing between shareholders and customers concerning meals and entertainment expenses. In Commission Order No. 09 – 020 (UE 197), the Commission agreed with Staff's recommendation concerning meals and entertainment expenses and ordered the 50 percent sharing between customers and shareholders. The Commission stated on page 21:[8]

> We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders.

As a result, I recommend a 50 / 50 sharing of meals and entertainment expenses between customers and shareholders. As previously stated, I did not make this adjustment based on the LCM analyses.

Q. DO YOU AGREE WITH PACIFICORP'S COMMENTS (PPL/401, LASICH/4) THAT IF THE COMMISSION SHOULD REJECT THE LOWER OF COST OR MARKET ADJUSTMENTS, THAT THE COMMISSION SHOULD ALSO REJECT THE LINE ITEM ADJUSTMENTS?

[8] Included in Exhibit Staff/403.

A. No. First, I believe the Commission should not reject the lower of cost or market (LCM) adjustments as explained later in testimony. Second, the Commission already addressed these issues in a previous order. In its UI 189 application, PacifiCorp references Commission Order No. 79-754 concerning Bridger Coal, which states (emphasis added):

> "Because of its affiliated relationship and the ***volume of its purchases***, PP&L does enjoy a ***position of dominance*** with regard to Bridger Coal which renders a comparison of prices of non-affiliated market transactions inadequate as a ***measure of reasonableness*** of PP&L's payments to Bridger Coal. The Commissioner should therefore ***disallow operating expenses*** which cause a greater return to Bridger Coal than that allowed PP&L.
>
> PP&L may finance Bridger operations as it chooses. However, for ratemaking purposes, the Commissioner will limit the return on PP&L on its Bridger investment to the level allowed on other PP&L operations" Order No. 79-754, pp. 19-20.[9]

The footnote on page 3 of the application lists the component base prices, which include Labor, Salaries & Related Costs. The result is that even when an affiliates' costs are lower than market, the component costs should be examined for reasonableness.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY CONCERNING LINE ITEM ADJUSTMENTS?

A. Yes.

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[9] Included in Exhibit Staff/403.

ISSUE 3, UPDATED ADJUSTMENTS TO PACIFICORP'S FUEL BURN EXPENSE

DAVE JOHNSTON FUEL BURN EXPENSE

Q. DO YOU AGREE WITH PACIFICORP THAT YOUR ADJUSTMENT TO THE DAVE JOHNSTON PLANT IS MOOT?

A. No. PacifiCorp in PPL/400, Morgan/4 states that because the August - 2010 TAM update includes the new fuel contracts, Staff's adjustment is rendered moot. However, PacifiCorp's update of $52,570,576 is only $20,000 lower than the initial filing cost of $52,590,391. A reduction in the cost per ton from $10.58 to $9.86 ($0.72 or 7.3 percent), would have resulted in a more significant reduction in costs as shown in Exhibit Staff/401, Dougherty/1.

Q. PLEASE PROVIDE YOUR UPDATED ADJUSTMENT TO DAVE JOHNSTON FUEL BURN EXPENSE.

A. Because the updated, actual cost is $0.72 lower than PacifiCorp's forecasted cost, I calculate the Dave Johnston Fuel Burn Expense as $52,075,269. As a result, my adjustment is reduced from $930,622-system ($250,122-Oregon) to $495,307-system ($133,123-Oregon).

HUNTINGTON FUEL BURN EXPENSE

Q. PLEASE PROVIDE YOUR UPDATED ADJUSTMENT TO HUNTINGTON.

A. PacifiCorp's August – 2010 TAM update decreased the Huntington Fuel Burn expense to $96,269,427 from the initial filing Fuel Burn Expense of $96,354,411. As a result, my adjustment is decreased to $1,123,083 system-wide ($301,850 - Oregon).

Q. DO YOU CONTINUE TO SUPPORT YOUR LCM ADJUSTMENT METHOD TO THE HUNTINGTON PLANT?

A. Yes. My adjustment should be accepted by the Commission because:

1. OAR 860-027-0048, *Allocation of Costs by an Energy Utility*, affirms the Commission's Transfer Pricing Policy. As a result, the charges for ratemaking purposes, from Deer Creek to PacifiCorp are required to be at LCM. The rule defines market rate as "the *lowest* price that is *available* from nonaffiliated suppliers for comparable services or supplies." (emphasis added)[10]
2. Lowest Price – As highlighted in my reply testimony, there is adequate data that clearly shows the existence of nonaffiliated prices for coal in the Utah region. The average third party delivered coal prices for coal supplied to Huntington [redacted] and Hunter [redacted] are lower than the Deer Creek mine delivered coal costs to Huntington at $33.22. The average delivered coal cost to the three Utah plants (Huntington, Hunter, and Carbon) is $32.29, is also lower than the Deer Creek mine delivered coal costs to Huntington. As explained in Staff/200, Dougherty/21-22, the $32.29 average cost, which is lower than the Deer Creek cost ($33.22), was the basis for my recommended adjustment.
3. Availability – The fact is that nonaffiliated coal is being used at all three Utah coal plants clearly demonstrates that a nonaffiliated supply is available. The total amount of coal being purchased from nonaffiliated

[10] OAR 860-027-0048(1)(i).

suppliers, according to PacifiCorp's confidential response to Staff Data Request No. 6[11] is [redacted] tons. This amount comprises approximately [redacted] percent of total coal (nonaffiliated and affiliated) being used at the three Utah plants.

Q. DO YOU AGREE WITH PACIFICORP'S COMMENTS (PPL/400, MORGAN/6) THAT PACIFICORP CUSTOMERS ARE NOT SUBSIDIZING ENERGY WEST?

A. No. Because the affiliate's price is higher than the market price, PacifiCorp customers are clearly subsidizing the higher cost of operations at Energy West (Deer Creek) as compared to nonaffiliated suppliers.

Q. DO YOU AGREE WITH PACIFICORP THAT THE SPOT MARKET PRICE SHOULD BE USED AS THE MARKET PROXY AS STATED IN PPL/400, MORGAN/6-7?

A. No. PacifiCorp's confidential responses to Staff Data Requests Nos. 5, 6, and 36 clearly demonstrates that nonaffiliated coal is being purchased by contract and not on the spot market in Utah. As a result, the Commission should not accept PacifiCorp's attempt to substitute a spot price for the actual contract prices being paid by the Company.

Q. DO YOU AGREE WITH PACIFICORP THAT THE PRICES YOU USED TO DETERMINE MARKET ARE NOT AVAILABLE PRICES AS STATED IN PPL/400, MORGAN/7?

[11] Confidential Exhibit Staff/205, Dougherty/4.

A. No. The plain fact is that PacifiCorp is purchasing coal for its Utah operations from [redacted] nonaffiliated mines. (Please see PacifiCorp's confidential response to Staff Data Request No. 6).[12]

Q. PLEASE ADDRESS PACIFICORP'S COMMENTS (PPL/400, MORGAN/7) CONCERNING THE SUFCO CONTRACT.

A. Concerning the Sufco contract, the prices of coal supplied to both the Hunter and Huntington plant are not static. Although the contract vintage is the late 1990s, the prices have increased over time. Customers are not paying late 1990s prices for this coal. As PacifiCorp's confidential response to Staff Data Request No. 36c[13] demonstrates, the costs of coal from this mine have [redacted]. These prices are FOB plant and include transportation charges. If the contract prices change in 2011 (PPL/500, Morgan/7) when the contract is renegotiated, Staff would use the updated prices in the LCM analysis for the 2011 TAM.

Q. PLEASE ADDRESS PACIFICORP'S COMMENTS (PPL/400, MORGAN/7-8) CONCERNING THE ELECTRIC LAKE CONTRACTS.

A. Although PacifiCorp provides more contemporary prices (Electric Lake, which supplies Carbon), a review of PacifiCorp's responses to Staff Data Requests Nos. 5 and 36, clearly shows that the 2010 nonaffiliated coal costs supplying Huntington are [redacted] It is important to note that I used the higher Electric Lake costs to

[12] Confidential Exhibit Staff/205, Dougherty/4.
[13] Confidential Exhibit Staff/205, Dougherty/6.

calculate the average third party cost of $32.29. As Staff/402, Dougherty/4 points out, if I only used the price of coal supplied to Huntington [redacted] in the LCM analysis, a higher system-wide adjustment of $3,303,554 ($887,893 – Oregon) is achieved. The use of average market costs was a fair method that actually benefited PacifiCorp as compared to using only the price of coal supplied to Huntington.

Q. PLEASE ADDRESS PACIFICORP'S COMMENTS (PPL/400, MORGAN/8.) CONCERNING LOWER QUALITY COAL BEING SUPPLIED TO HUNTER, WHICH IS NOT COMPARABLE TO DEER CREEK COAL.

A. The average coal cost being supplied to Hunter is lower than the nonaffiliated coal cost to Huntington. However, it is important to note that two of the three coal contracts supplying Hunter (not including transportation) are actually higher than the contract coal cost of coal supplying Huntington.[14] Additionally, if I disregard the lower average Hunter cost than it would be reasonable to disregard the higher Carbon costs. As previously mentioned, if I only used the price of coal supplied to Huntington [redacted] in the LCM analysis, a higher system-wide adjustment of $3,303,554 ($887,893 – Oregon) is achieved. The use of average market costs was a fair method that actually benefited PacifiCorp as compared to using only the price of coal supplied to Huntington.

Q. PLEASE ADDRESS PACIFICORP'S COMMENTS (PPL/400, MORGAN/8) CONCERNING THE LOWER DEER CREEK COSTS TO THE HUNTER PLANT.

[14] Confidential Exhibit Staff/205, Dougherty/1 - 2.

A. I previously explained the difference in pricing between Hunter and Huntington plants in Staff/200, Dougherty/23. Basically, because the transfer of coal to Hunter does not occur at an equal pro-rata basis throughout the year,[15] the Deer Creek coal delivered to Hunter was actually lower than the third party coal supplied to the Hunter plant. The difference appears to be a timing issue concerning coal delivery.

Q. PLEASE SUMMARIZE YOUR LCM ADJUSTMENT TO HUNTINGTON FUEL BURN EXPENSE.

A. OAR 860-27-0048, *Allocation of Costs by an Energy Utility* affirms the Commission's Transfer Pricing Policy. As a result, the charges for ratemaking purposes, from Deer Creek to PacifiCorp are required to be at the lower of cost or market. As demonstrated above, there is adequate data that demonstrates that comparable coal is available from nonaffiliated suppliers at lower costs than the cost of coal being supplied to Huntington by Deer Creek mine. PacifiCorp's August – 2010 TAM update decreased the Huntington Fuel Burn expense to $96,269,427 from the initial Huntington Fuel Burn Expense of $96,354,411. As a result, my adjustment is reduced to $1,123,083 system-wide ($301,850-Oregon).

Q. DO YOU HAVE ADDITIONAL COMMENTS CONCERNING THE HUNTINGTON PLANT?

A. Yes. As a result of recent information obtained, I discovered that the Huntington coal cost in PacifiCorp's general rate case filing in Utah is

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

$76,034,135,[16] which is significantly (approximately 27 percent) lower than the Oregon August – 2010 TAM update of $96,269,427. As a result, Utah's cost is $11.44/MWh as compared to Oregon's cost of $14.52/MWh. Although the time period of Utah's cost (July 2009 – June 2010) lags Oregon's time period (January 2010 – December 2010) by six months, the increase appears excessive for the following reasons:

1. The 2010 Deer Creek cost [redacted] increase from 2009 cost [redacted] is only [redacted] percent. Significantly less than the 27 percent difference between Utah and Oregon's cost.

2. According to PacifiCorp's response to Staff Data Request No. 31c,[17] the pro-rata nature of deliveries show higher delivery costs in the first half of 2010, a time period that is shared by both Oregon and Utah.

3. Also according to PacifiCorp's response to Staff Data Request No. 31c, the pro-rata nature of deliveries indicate a lower than average cost per ton for five of the six months between July 2010 to December 2010; the time period that is exclusively included in Oregon costs.

4. If I replace the high pro-rata costs in the months of March, April, and May 2010 with the average Deer Creek cost of $33.22, I receive a total cost in the range of the Utah 2009-2010 cost.[18]

5. The coal generation in Exhibit PPL (TAM)/103, Duvall/10 is 6,628,572 MWh for Oregon and 6,648,682 MWh in Utah. So although Utah's cost is approximately $20 million lower than Oregon's, the power being produced is higher for Utah time period.

As a result, the $20 million difference cannot be easily explained by the timing difference between the Utah and Oregon filings. As a result, Staff will need additional time to determine the reasonableness of the differences between

[16] _UT GRC NPC – June 2010 Gold_2009 05 29. Included in Staff Exhibit 403.
[17] Confidential Exhibit Staff/404. Modified to show Staff's replacement calculations.
[18] *Ibid.*

Utah and Oregon. Until a further analysis is conducted, I continue to recommend the LCM adjustment be accepted by the Commission.

BRIDGER FUEL BURN EXPENSE

Q. PLEASE PROVIDE YOUR UPDATED ADJUSTMENT TO BRIDGER.

A. PacifiCorp's August – 2010 TAM update increased the Bridger Fuel Burn expense to $181,224,458 from the initial filing Fuel Burn Expense of $180,236,369. As a result, my adjustment is increased to $18,843,476 system-wide ($5,064,542 - Oregon).

Q. DO YOU CONTINUE TO SUPPORT YOUR ADJUSTMENT METHOD TO THE BRIDGER PLANT?

A. Yes. My adjustment should be accepted by the Commission because:

1. OAR 860-027-0048, *Allocation of Costs by an Energy Utility*, affirms the Commission's Transfer Pricing Policy. As a result, the charges for ratemaking purposes, from Bridger Coal Company (BCC) to PacifiCorp are required to be at the lower of cost or market. The rule defines market rate as "the *lowest* price that is *available* from nonaffiliated suppliers for comparable services or supplies."(emphasis added)[19]
2. Lowest Price – As highlighted in my July 14, 2009, reply testimony, there is adequate data that clearly shows that there are lower nonaffiliated prices for coal in the Green River Basin (GRB) area of Wyoming. The

[19] OAR 860-027-0048(1)(i).

nonaffiliated Black Butte[20] delivered coal prices for coal supplied to Bridger [redacted][21] is significantly lower than the BCC mine delivered coal costs to Bridger at [redacted]. Additionally, the nonaffiliated Kemmerer delivered coal cost to Naughton [redacted] is also lower than the BCC delivered coal costs to Bridger. As explained in Staff/200, Dougherty/12-15, I substituted the [redacted] average cost of Kemmerer and Black Butte for BCC's [redacted] operations cost of [redacted], to receive a weighted cost of [redacted].

3. Availability – The fact that nonaffiliated Black Butte coal supplies approximately one-third of Bridger clearly demonstrates that a nonaffiliated supply is available. The total amount of coal being purchased from nonaffiliated suppliers in the GRB region, according to PacifiCorp's confidential response to Staff Data Request No. 6[22] is [redacted] tons. This amount comprises approximately [redacted] percent of total coal (nonaffiliated and affiliated) being used at PacifiCorp's GRB plants.

Additionally, Commission Order No. 79-754, page 17, refers to the Company's position and states (emphasis added):

> "(2) Unlike the telephone affiliates, an ***alternate market exists for coal sold to PP&L*** at a price higher than the price charged PP&L ratepayers."[23]

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[20] Staff notes that in its UI 189 application, PacifiCorp on page 5, footnote 2, specifically states that BCC and Black Butte "are of comparable quality."
[21] The actual coal cost not including transportation is [redacted].
[22] Confidential Exhibit Staff/205, Dougherty/4-5.
[23] Included in Staff Exhibit/403.

It is curious that PacifiCorp claims that there is not an available market in 2010 when the Company claimed in 1979 that an alternate market existed.

Q. PLEASE SUMMARIZE WHY YOU BELIEVE YOUR PRIMARY RECOMMENDATION IN STAFF/200, DOUGHERTY/15 SHOULD BE ACCEPTED BY THE COMMISSION.

A. I believe my primary recommendation as outlined in Staff/200, Dougherty/15 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 (comparable and available coal);

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. DO YOU AGREE WITH PACIFICORP'S COMMENTS (PPL/400, MORGAN/10) THAT PACIFICORP CUSTOMERS ARE NOT SUBSIDIZING BRIDGER COAL COMPANY?

A. No. Because the affiliate's price is higher than the market price, PacifiCorp customers are clearly subsidizing the higher cost of operations at BCC as compared to nonaffiliated suppliers. Even with the effect of EITF 04-6, BBC's costs ($30.70) are [redacted] than the average of nonaffiliated GRB area coal costs [redacted]. I believe the focus should be on the cost of coal delivered to the two GRB coal plants. For the GRB region, the BCC coal cost is substantially [redacted] than the Black Butte and Naughton[24] costs.

[24] Naughton is FOB plant, so there may be a small transportation component to the cost.

Q. PLEASE RESPOND TO PACIFICORP'S COMMENTS (PPL/400, MORGAN/10-11) ABOUT YOU SUBSTITUTING ONLY THE COST OF ONE COMPONENT IN YOUR LCM ANALYSIS.

A. PacifiCorp's testimony in PPL/201, Lasich/2-3 demonstrates that BCC's weighted cost is affected by the surface mining operations. However, my recommendation is an adjustment from ***BCC's weighted costs***. This is clearly demonstrated on Staff/200, Dougherty/10–20. It is important to note that in Staff/200, Dougherty/19-20, I performed a fourth analysis where I averaged the Black Butte and Naughton coal costs to determine a LCM pricing. The resulting adjustment is a $21,607,763 system-wide ($5,807,497 – Oregon). If PacifiCorp believes that this is a more appropriate analysis, I would be supportive of this method and the subsequent adjustment. If the Commission decides to use this method, my overall Fuel Burn Expense adjustment would increase to $23,226,153 ($6,242,470 – Oregon).

Q. PLEASE RESPOND TO PACIFICORP'S COMMENTS (PPL/400, MORGAN/11) ABOUT NO AVAILABLE SUPPLY FROM BLACK BUTTE MINE.

A. It is important to note that OAR 860-027-0048 addresses lower of cost or market pricing. It does not address a company's penetration or participation in the market. What is known is:

1. One-third of the coal used at Bridger comes from Black Butte;
2. The cost of coal from Black Butte is significantly lower than the BCC cost of coal; and

3. The focus of the LCM should be on the price of coal that is produced at available mines and delivered to GRB coal plants.

Q. PLEASE RESPOND TO PACIFICORP'S COMMENTS (PPL/400, MORGAN/11-12) ABOUT THE CARRY-OVER COST OF THE BLACK BUTTE COAL.

A. I used the Black Butte 2010 cost as reflected in PacifiCorp's response to Staff Data Response No. 5.[25] This is the actual cost that PacifiCorp is paying for this coal. It is ridiculous for PacifiCorp to assert that customers should not benefit from carry-over tonnage. In addition, PacifiCorp conveniently ignores the actual effect on the overall adjustment if the carry-over tonnage was not included. Because of the [redacted] percentage of surface coal, the Bridger LCM adjustment would be reduced to $17,941,682 system-wide ($4,822,168 - Oregon) from the $18,843,476 system-wide ($5,064,542) primary adjustment. Confidential Exhibit Staff/403, Dougherty/3 shows this analysis. I do not recommend that the Commission accept any LCM that does not use 2010 prices as reported in PacifiCorp's confidential response to Staff Data request No.5.[26]

Q. PLEASE RESPOND TO PACIFICORP'S COMMENTS (PPL/400, MORGAN/12) ABOUT KEMMERER COAL NOT BEING AVAILABLE

A. As previously mentioned, I believe the focus should be on the cost of coal. For the GRB region, the BCC coal cost is substantially higher than the Black Butte and Naughton coal costs.

[25] Confidential Exhibit Staff/205, Dougherty/1.
[26] Confidential Exhibit Staff/205, Dougherty/1.

Q. PLEASE RESPOND TO PACIFICORP'S COMMENTS (PPL/400, MORGAN/13) ABOUT THE AVERAGE PRICE OF $36.97 THAT SHOULD BE USED FOR THE LCM?

A. There are two problems with PacifiCorp's average price of $36.97. These are:

1. PacifiCorp is not recognizing the carry-over tonnage that should benefit customers; and

2. PacifiCorp is failing to recognize its higher cost of operations at BCC. As stated previously, the focus should be on the cost of coal. Currently, BCC's costs are significantly [redacted] than nonaffiliated costs.

As a result, the Commission should not accept PacifiCorp's recommended average price of $36.97.

Q. PLEASE RESPOND TO PACIFICORP'S COMMENTS (PPL/400, MORGAN/13-14) ABOUT YOUR SECONDARY AND THIRD MARKET ANALYSES.

A. My secondary and third market analyses, as explained in Staff/200, Dougherty/15-19, are alternate recommendations for the Commission to consider. I believe my primary recommendation as outlined in Staff/200, Dougherty/15 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 (comparable and available coal);

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.

However as previously stated, I would be supportive of the fourth method (average price of Black Butte and Kemmerer) and the subsequent adjustment. If the Commission decides to use this method, my overall Fuel Burn Expense adjustment would increase to $23,226,193 ($6,242,481 – Oregon).

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. For Dave Johnston, I calculated the fuel burn expense using PacifiCorp's updated Open Position costs. For Huntington and Bridger, I continue to apply the lower of cost or market standard to determine the Huntington and Bridger adjustments. My recommended adjustments to PacifiCorp's coal fuel burn expense are highlighted in the following table.

Table 3 – Summary of Staff Adjustments

Plant	**PacifiCorp's August 2010 TAM Update**	**Staff**	**Adjustment**
Dave Johnston	$52,570,576	$52,075,269	$495,307
Huntington	$96,269,427	95,146,344	$1,123,083
Jim Bridger	$181,224,418	$162,380,942	$18,843,476
Total	**$330,064,421**	**$309,602,556**	**$20,461,865**
Total Oregon Adjustment Based on SG Factor			**$5,499,515**

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

CASE: UE 207
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Exhibit in Support
Of Surrebuttal Testimony

August 25, 2009

UE 207 - Coal Fuel Burn Adjustments

	PacifiCorp August 2010 Update	Staff	Adjustment	Staff Alternate Amount	Staff First Alternate Adjustment	
Dave Johnston	52,570,576	52,075,269	495,307	52,075,269	495,307	Confidential Exhibit Staff 402
Huntington	96,269,427	95,146,344	1,123,083	92,965,873	1,123,083	Confidential Exhibit Staff 402
Jim Bridger	181,224,418	162,380,942	18,843,476	163,012,338	18,212,080	Confidential Exhibit Staff 402
Total	330,064,421	309,602,556	20,461,865	308,053,481	19,830,469	
Recommended Adjustment	20,461,865	5,499,515	Oregon	Bridger Market - Uses certain BCC operations and average 3rd party coal costs. Huntington Market - Based on Carbon, Hunter, and Huntington 3rd party costs. Dave Johnston - Based on updated price.		
Recommended First Alternate	19,830,469	5,329,815	Oregon	Bridger Market - Alternate Calculation based on Bridger Underground Mine Cost. Huntington Market - Based on Carbon, Hunter, and Huntington 3rd party costs. Dave Johnston - Based on updated price.		
Recommended Second Alternate	13,640,767	3,666,215	Oregon	Uses PRB coal price replacing certain BCC operations. Huntington Market - Based on Carbon, Hunter, and Huntington 3rd party costs. Dave Johnston - Based on updated price.		
Fourth Analysis for BCC	23,226,153	$ 6,242,470	Oregon	Bridger Market - Uses certain BCC operations and average 3rd party coal costs. Huntington Market - Based on Carbon, Hunter, and Huntington 3rd party costs. Dave Johnston - Based on updated price.		

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

Dave Johnston	495,307	
	133,123	Oregon

CASE: UE 207
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 402

Exhibits in Support of Surrebuttal Testimony

<u>REDACTED VERSION</u>
August 25, 2009

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 402 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 403

Exhibit in Support
of Surrebuttal Testimony

August 25, 2009

Request:

1.4 See Staff/200, Dougherty/11-12. Why did Staff include the costs of EITF 04-6 compliance in the Bridger coal supply costs it compared to market prices?

a. If EITF04-6 causes costs to go higher in some years and lower in others, how does Staff propose to control for this factor in its "lower of cost or market" analysis to ensure against asymmetrical cost recovery (i.e. where customers get the benefit of EITF 04-6 in low cost years but do not pay the full cost in high cost years)?

Response:

Staff included the EITF 04-6 cost because it is a component of the BCC costs. PacifiCorp also included this cost in its weighted cost. Additionally, in its response to Staff Data Request No. 51, the Company provides an estimated price of BCC coal if EITF 04-6 was not included.

PacifiCorp's confidential response to Staff Data Request 36c includes prices of all third party suppliers. Because EITF 04-6 costs applies to mining entities, these third party suppliers would also be exposed to the effect of EITF 04-6.

a. Staff does not propose to control EITF 04-6 effects on its lower of cost or market analysis. If market costs on any particular year are higher than PacifiCorp's costs, than PacifiCorp's costs would be a starting point for Staff's recommendation. Please note that customers would only see a "benefit" of EITF 04-6 if PacifiCorp's costs are lower than market in "low cost years."

Mr. Rooks testified that he works under a contract with the Company that calls for an hourly wage. He claims that Staff's recommendation will result in the Company violating state and federal laws.

According to Mr. Rooks, in the history of Crooked River, no one has been salaried – wages always have been hourly, and the Company intends to continue in this manner. Mr. Rooks states that the policy allows the Company to better match revenues and expenses.

The Company warns that exclusion of overtime will impair its ability to provide fire protection service.

Mr. Rooks testified that his actions do not warrant the Staff's adjustment for failure to comply with data requests. He states that answers were provided that "were deemed relevant to the company regarding the rate case."

c. Intervenors Soule and Nichols

Intervenors Soule and Nichols support the Staff's adjustments to salaries and wages. They also note that the Company incurs higher costs ($5,980 annually) on account of the General Manager's failure to obtain a Water Operator 2 classification, requiring the Company to use the services of a Water Operator 3 on a part-time basis, to meet the certification requirements of the state's Drinking Water Program.

d. Discussion

We adopt Staff's proposal. The Commission does not prescribe the amount of compensation for any utility employee to be paid by the utility. We determine a reasonable amount of compensation to be recovered from customers through rates.

In its application, the Company proposes wage levels for three employees that include very substantial amounts of overtime. As Staff notes, in most cases a General Manager position is salaried and the general manager would not earn overtime. Further, there is no evidence that the hours claimed are reasonable or necessary to perform the duties of the three positions.

Staff has calculated a reasonable level of salary and wage expense. The allowance for an additional full time employee should assure that the staff proposal is adequate to provide reliable service. Crooked River has the burden of proving that its estimate of test year salaries and wages is reasonable. The Company has failed to meet its burden of proof.

Staff's further adjustment to the General Manager's salary to reflect discovery failures is well taken. In the case of an investor-owned utility we might respond to management indiscretion by way of an adjustment to return on equity. Given

Staff also proposes removing 100 percent of civic activities recorded in Administrative & General (A&G) accounts, noting "the Commission has not previously allowed regulated utilities to recover contributions to charities, community affairs, and economic development organizations through rates charged for regulated services. . . . In addition, Commission policy does not require customers to support causes in which they do not believe."[79]

PGE asserts that these discretionary costs are appropriately included in rates, because these miscellaneous expenses create a business culture that allows the utility to attract and retain qualified workers.[80]

Resolution

We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders. We also adopt Staff's recommendation with respect to contributions to charities, community affairs, and economic development organizations. PGE provides no rationale to change our existing policies, and we conclude that all contributions to charities, community affairs, and economic development organizations should be disallowed. PGE's 2009 revenue requirement is reduced by $710,000 to reflect the disallowance of these expenses.

We also acknowledge PGE's removal of Directors' Compensation and Officer Vehicles from the proposed 2009 test-year budget. The total revenue-requirement reduction for miscellaneous expenses is $1.18 million.

i. Senate Bill 408 Ratio Adjustment

Senate Bill 408 (SB 408) requires the Commission to establish certain ratios in general ratemaking proceedings, which will be used to determine the amounts of "taxes collected" from customers for the purpose of the SB 408 true-up of "taxes paid" to "taxes collected." PGE believes that, in setting the tax rate and margin ratios here for SB 408 purposes, the Commission should consider the impact of costs that have been disallowed. PGE explains that, "[t]o do otherwise would effectively allow customers to receive tax benefits from utility costs for which customers are not responsible."[81]

Staff opposes PGE's proposal as an attempt to insulate its shareholders from sharing the tax benefit of disallowed expenses with ratepayers when truing up the amount of taxes collected. Staff believes PGE's request is inconsistent with the terms of SB 408, as well as Commission rules implementing the bill.[82] According to Staff, the Commission indirectly addressed this issue when it declined PGE's request for a deferral

[79] *Id.*, citing Staff/300, Ball-Dougherty/15.
[80] PGE Opening Brief at 37, citing PGE/2700, Piro-Tooman/12.
[81] PGE/2300, Tooman-Tinker/24.
[82] *See* ORS 757.268 and OAR 860-022-0041.

5. Costs of the Goods Provided

Attached as Application Exhibit No. 1 are copies of the Third Restated and Amended Coal Sales Agreement (January 1, 1996) ("Third Restated Agreement") and the First Amendment thereto (January 1999) (together referred to hereafter as the "Coal Supply Agreement"). These contracts establish the terms and conditions under which coal is supplied by Bridger Coal to PacifiCorp and Idaho Power for use at the Jim Bridger generation plant.

The coal supply agreement with Bridger Coal establishes annual base tonnages for coal purchases. The annual base tonnage for both 2000 and 2001 is 5,232,600 tons. Section 2.01, Third Restated Agreement. PacifiCorp and Idaho Power have the right to supplement these base tonnages. Id., Section 2.02.

Coal price is determined through establishment of component base prices[1] as adjusted pursuant to the price change provisions in Section 6 of the Third Restated Agreement.

The Company's Oregon retail electric prices, however, reflect a limitation on the coal supply prices paid by PacifiCorp. In Order No. 79-754, the Commission made the following findings regarding PacifiCorp's coal purchases from Bridger Coal:

> "PP&L does purchase the fuel required to operate its Jim Bridger plant from Bridger Coal. Because of its affiliated relationship and the volume of its purchases, PP&L does enjoy a position of dominance with regard to Bridger Coal which renders a comparison of prices of non-affiliated market transactions inadequate as a measure of reasonableness of PP&L's payments to Bridger Coal. The Commissioner should therefore disallow operating expenses which cause a greater return to Bridger Coal than that allowed PP&L.
>
> "PP&L may finance Bridger operations as it chooses. However, for ratemaking purposes, the Commissioner will limit the return to PP&L on its Bridger investment to that level allowed on other PP&L operations." Order No. 79-754, pp. 19-20.

[1] Components include Labor, Salaries & Related Costs (§ 6.02), Materials & Supplies (§ 6.03), Electric Power (§ 6.04), Inflation & Deflation (§ 6.05), Ad Valorem, Severance, Property & License Taxes (§ 6.06), Costs Based Upon Extraction (§ 6.07), Other New, Increased Taxes (§ 6.08), Additional Costs (§ 6.09), Transfer Taxes (§ 6.10), Black Lung (§ 6.11); Federal Reclamation Fee (§ 6.12), and Final Reclamation (§ 6.13) of the Third Restated Agreement.

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Net Power Cost Analysis

12 months ended June 2010	07/09-06/10	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10
Wheeling & U. of F. Expense													
Firm Wheeling	140,897,457	10,422,540	10,003,696	12,952,854	10,697,095	11,782,687	11,779,015	12,401,508	11,733,758	12,226,661	11,961,063	12,292,242	12,644,339
ST Firm & Non-Firm	952,117	59,178	67,340	80,309	95,813	113,790	125,010	104,065	64,479	61,724	40,201	68,234	71,974
Total Wheeling & U. of F. Expense	141,849,574	10,481,718	10,071,036	13,033,163	10,792,908	11,896,477	11,904,025	12,505,573	11,798,237	12,288,385	12,001,264	12,360,476	12,716,313
Coal Fuel Burn Expense													
Carbon	19,120,765	1,603,482	1,605,460	1,407,298	1,416,272	1,102,205	1,760,742	1,761,852	1,626,662	1,782,445	1,803,157	1,650,348	1,600,843
Cholla	54,384,462	4,696,636	4,692,410	4,556,368	4,641,051	4,599,463	4,850,189	4,924,129	4,439,950	2,536,647	4,872,286	4,888,645	4,686,689
Colstrip	11,907,943	1,048,006	1,046,046	811,840	827,260	1,012,967	1,048,006	1,046,046	945,827	1,048,006	1,013,946	1,046,046	1,013,946
Craig	19,589,117	1,684,424	1,690,624	1,592,806	1,650,401	1,617,863	1,677,541	1,702,994	1,537,919	1,568,120	1,537,545	1,698,274	1,630,607
Dave Johnston	52,178,639	4,526,665	4,524,597	4,129,288	3,650,845	4,105,044	4,557,394	4,555,180	4,115,550	4,545,595	4,410,113	4,602,544	4,455,824
Hayden	11,469,930	1,002,262	1,002,136	970,059	1,002,285	969,910	1,002,435	1,002,136	905,309	671,140	970,059	1,002,136	970,059
Hunter	107,289,793	9,014,965	9,122,805	8,243,621	8,546,582	9,453,471	9,730,057	9,761,955	8,815,351	7,067,045	9,267,246	9,354,719	8,911,976
Huntington	76,034,135	6,505,859	6,570,044	6,241,323	6,509,009	6,634,528	6,814,971	6,839,542	6,173,693	6,847,336	3,878,047	6,642,372	6,377,414
Jim Bridger	168,435,956	15,019,933	15,072,633	14,404,023	14,923,445	14,561,975	15,052,514	14,892,837	13,524,650	14,461,268	10,793,849	11,188,229	14,540,601
Naughton	79,192,952	6,895,681	6,885,971	6,671,987	6,890,826	6,707,607	6,919,639	6,927,410	6,255,031	6,922,861	4,907,687	6,536,266	6,671,987
Wyodak	19,411,986	1,682,964	1,681,406	1,628,473	1,682,185	1,004,141	1,729,203	1,728,238	1,561,818	1,729,844	1,673,835	1,681,406	1,628,473
Total Coal Fuel Burn Expense	619,015,678	53,680,876	53,894,132	50,657,086	51,740,161	51,769,173	55,142,689	55,142,319	49,901,761	49,180,306	45,127,770	50,290,984	52,488,420
Gas Fuel Burn Expense													
Chehalis	53,155,990	5,438,750	8,323,041	7,948,837	7,880,296	-	10,905,032	12,660,035	-	-	-	-	-
Currant Creek	60,537,903	5,470,359	5,918,429	5,965,497	5,162,735	3,639,888	4,443,562	6,259,266	4,638,166	4,776,879	5,603,657	4,246,251	4,413,214
Gadsby	4,859,768	1,579,088	1,830,684	1,167,124	-	-	-	-	-	-	-	282,872	-
Gadsby CT	5,654,519	965,356	976,581	803,457	531,886	635,057	-	719,292	390,332	-	-	-	632,557
Hermiston	56,783,207	4,911,643	5,146,137	5,005,478	5,235,862	5,368,360	5,659,941	5,431,999	4,970,996	5,554,885	3,731,657	2,611,443	3,154,807
Lake Side	85,692,649	7,728,260	7,956,763	7,395,592	6,208,850	5,463,400	5,563,203	8,856,468	6,677,844	6,533,922	9,686,143	6,813,645	6,808,559
Little Mountain	5,873,470	50,889	122,351	-	441,480	603,546	786,862	854,491	776,052	843,525	728,900	665,374	-
Total Gas Fuel Burn	272,557,507	26,144,345	30,273,986	28,285,985	25,461,107	15,710,250	27,358,601	34,781,551	17,453,390	17,709,211	19,750,358	14,619,585	15,009,137
Gas Physical	(492,814)	(106,555)	(105,780)	(103,249)	(110,069)	(1,806)	4,236	6,761	6,264	6,354	(30,199)	(30,598)	(28,174)
Gas Swaps	174,152,653	24,855,335	24,167,910	22,765,500	20,930,115	16,993,860	12,951,180	8,782,067	7,362,278	8,402,194	9,050,550	9,400,014	8,491,650
Clay Basin Gas Storage	(1,130,387)	52,466	52,466	52,466	52,466	(93,659)	(291,422)	(373,390)	(379,091)	(360,088)	52,466	52,466	52,466
Pipeline Reservation Fees	26,976,411	2,275,109	2,275,109	2,234,119	2,275,109	2,234,119	2,275,109	2,275,109	2,160,328	2,275,109	2,218,733	2,259,723	2,218,733
Additional Fixed Costs	6,331,298	484,196	109,417	158,740	75,115	478,562	833,621	856,725	664,305	713,836	417,882	788,637	750,263
Total Gas Fuel Burn Expense	478,394,667	53,704,896	56,773,109	53,393,562	48,683,844	35,321,326	43,131,325	46,328,823	27,267,474	28,746,616	31,459,790	27,089,827	26,494,075
Other Generation													
Blundell	3,897,089	333,744	333,845	322,991	247,620	274,628	354,603	354,710	320,328	354,603	343,178	333,845	322,991
Wind Integration Charge	28,287,667	1,829,919	1,782,087	1,948,237	2,283,515	2,674,209	2,915,672	2,921,723	2,382,086	2,581,999	2,336,121	2,317,962	2,314,139
Total Other Generation	32,184,756	2,163,663	2,115,932	2,271,228	2,531,134	2,948,837	3,270,275	3,276,433	2,702,414	2,936,602	2,679,299	2,651,807	2,637,131
Net Power Cost	999,143,849	110,766,432	115,766,607	95,698,152	72,800,304	72,368,954	76,114,662	72,874,338	71,765,634	73,382,945	77,901,780	76,315,334	83,388,708
Net Power Cost/Net System Load	17.15	20.83	21.98	20.53	16.14	15.56	14.56	13.94	15.26	15.45	17.28	16.68	17.20

PacifiCorp

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Net Power Cost Analysis

12 months ended June 2010	07/09-06/10	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10
Coal Generation													
Carbon	1,154,544	96,563	96,690	83,769	84,111	65,800	106,996	106,985	99,021	108,419	110,006	99,570	96,614
Cholla	2,841,633	245,222	244,991	237,915	242,250	240,248	253,500	257,442	232,136	132,622	254,893	255,517	244,897
Colstrip	1,167,661	102,772	102,562	79,613	81,119	99,325	102,772	102,562	92,745	102,772	99,429	102,562	99,429
Craig	1,333,737	114,677	115,122	108,323	112,259	110,148	114,223	115,998	104,753	106,777	104,777	115,664	111,015
Dave Johnston	5,880,435	510,120	509,880	465,205	411,342	462,641	513,605	513,348	463,807	512,245	497,006	518,885	502,350
Hayden	634,289	55,430	55,423	53,650	55,432	53,641	55,440	55,423	50,068	37,060	53,650	55,423	53,650
Hunter	7,864,611	658,244	666,893	598,840	621,213	695,866	716,056	718,332	648,869	520,106	682,666	685,490	652,035
Huntington	6,648,682	567,947	573,903	544,499	568,200	580,876	596,610	598,783	540,499	599,487	339,631	581,134	557,113
Jim Bridger	10,310,080	919,495	923,174	880,846	912,906	891,800	921,840	911,225	827,940	885,786	660,087	684,865	890,117
Naughton	5,370,784	467,557	466,876	452,387	467,217	454,914	469,289	469,814	424,218	469,495	333,022	443,609	452,387
Wyodak	2,136,096	184,986	184,800	178,995	184,893	110,632	190,515	190,400	172,073	190,591	184,419	184,800	178,995
Total Coal Generation	45,342,552	3,923,012	3,940,315	3,684,041	3,740,941	3,765,890	4,040,844	4,040,313	3,656,130	3,665,360	3,319,584	3,727,519	3,838,601
Gas Generation													
Chehalis	1,645,019	215,359	318,691	294,954	272,918	-	258,601	284,496	-	-	-	-	-
Currant Creek	2,171,053	253,204	263,071	285,522	251,698	136,828	130,434	169,438	124,369	129,674	172,432	125,250	129,135
Gadsby	125,701	41,942	47,718	31,219	-	-	-	-	-	-	-	4,822	-
Gadsby CT	119,905	25,551	24,613	20,628	12,360	12,023	-	9,901	5,327	-	-	-	9,502
Hermiston	1,672,420	150,660	159,331	153,731	162,679	159,221	169,860	160,832	144,844	165,967	101,927	62,078	81,291
Lake Side	3,282,227	383,628	377,708	371,804	318,649	223,773	176,509	262,859	198,478	197,039	327,252	226,092	218,437
Little Mountain	81,578	964	2,333	-	8,884	10,030	10,364	10,364	9,361	10,364	10,030	8,884	-
Total Gas Generation	9,097,903	1,071,308	1,193,464	1,157,856	1,027,187	541,874	745,769	897,890	482,379	503,045	611,641	427,125	438,365
Hydro Generation													
West Hydro	3,879,539	189,659	171,460	178,494	168,953	297,241	421,654	551,421	454,879	410,233	409,091	337,134	289,319
East Hydro	355,019	41,992	36,643	19,947	15,706	15,676	18,774	18,864	18,359	35,019	41,041	50,279	42,721
Total Hydro Generation	4,234,558	231,652	208,102	198,441	184,659	312,917	440,428	570,285	473,238	445,252	450,131	387,413	332,040
Other Generation													
Blundell	173,899	14,661	14,665	14,188	10,877	12,435	16,057	16,062	14,505	16,057	15,539	14,665	14,188
Blundell Bottoming Cycle	86,961	7,679	7,682	7,432	5,698	5,947	7,679	7,682	6,937	7,679	7,432	7,682	7,432
Total Blundell	260,860	22,340	22,347	21,620	16,575	18,383	23,736	23,743	21,442	23,736	22,971	22,347	21,620
Foote Creek I	102,699	4,253	4,466	6,260	9,075	11,269	12,794	12,892	10,506	10,105	7,611	7,605	5,865
Glenrock Wind	323,799	18,452	19,953	23,835	28,531	31,729	37,436	36,072	27,959	29,575	26,501	21,938	21,816
Glenrock III Wind	124,409	7,094	7,676	9,169	10,960	12,182	14,375	13,846	10,745	11,363	10,181	8,432	8,385
Goodnoe Wind	266,887	27,556	23,970	18,281	23,542	20,857	14,214	13,956	18,183	31,076	22,609	24,419	28,225
High Plains Wind	243,996	-	-	-	12,469	31,025	35,902	35,480	27,001	29,176	25,636	26,751	20,556
Leaning Juniper 1	305,473	35,958	30,532	25,784	24,369	18,181	18,066	16,176	17,454	29,577	23,680	31,823	33,873
Marengo I	393,136	31,293	30,373	29,681	32,407	31,668	34,139	32,850	33,648	35,285	35,941	33,338	32,512
Marengo II	187,226	12,975	13,096	12,325	12,202	16,669	14,013	25,913	18,628	19,890	13,929	12,361	15,227
McFadden Ridge Wind	68,561	-	-	-	3,862	7,855	10,086	10,317	7,908	9,091	6,996	7,019	5,426
Rolling Hills Wind	292,594	16,121	16,915	21,093	25,460	29,558	34,890	33,084	25,798	26,883	23,900	19,406	19,487
Seven Mile Wind	349,596	17,024	19,928	21,606	29,584	35,802	40,304	43,929	30,606	36,878	26,476	25,496	21,961
Seven Mile II Wind	68,862	3,353	3,925	4,256	5,827	7,052	7,939	8,653	6,029	7,264	5,215	5,022	4,326
Total Wind Generation	2,727,238	174,079	170,835	172,291	218,288	253,848	274,158	283,167	234,465	276,162	228,676	223,610	217,658
Total Other Generation	2,988,098	196,419	193,182	193,911	234,863	272,231	297,894	306,911	255,907	299,898	251,647	245,957	239,279
Total Resources	74,032,222	6,823,995	6,747,277	6,207,914	6,123,562	6,037,769	6,811,004	6,782,981	5,798,332	5,864,738	5,516,491	5,573,304	5,744,855

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Net Power Cost Analysis

PacifiCorp

12 months ended June 2010	07/09-06/10	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10
Thermal Resources													
Blundell	14.94	14.94	14.94	14.94	14.94	14.94	14.94	14.94	14.94	14.94	14.94	14.94	14.94
Carbon	16.56	16.61	16.60	16.80	16.84	16.75	16.46	16.47	16.43	16.44	16.39	16.57	16.57
Cholla	19.14	19.15	19.15	19.15	19.16	19.14	19.13	19.13	19.13	19.13	19.12	19.13	19.14
Colstrip	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20
Craig	14.69	14.69	14.69	14.70	14.70	14.69	14.69	14.68	14.68	14.69	14.67	14.68	14.69
Dave Johnston	8.87	8.87	8.87	8.88	8.88	8.87	8.87	8.87	8.87	8.87	8.87	8.87	8.87
Hayden	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.11	18.08	18.08	18.08
Hunter	13.64	13.70	13.68	13.77	13.76	13.59	13.59	13.59	13.59	13.59	13.58	13.65	13.67
Huntington	11.44	11.46	11.45	11.46	11.46	11.42	11.42	11.42	11.42	11.42	11.42	11.43	11.45
Jim Bridger	16.34	16.33	16.33	16.35	16.35	16.33	16.33	16.34	16.34	16.33	16.35	16.34	16.34
Naughton	14.75	14.75	14.75	14.75	14.75	14.74	14.74	14.74	14.74	14.75	14.74	14.73	14.75
Wyodak	9.09	9.10	9.10	9.10	9.10	9.08	9.08	9.08	9.08	9.08	9.08	9.10	9.10
Total Coal Expenses	13.65	13.68	13.68	13.75	13.83	13.75	13.65	13.65	13.65	13.42	13.59	13.49	13.67
Chehalis	32.31	25.25	26.12	26.95	28.87	-	42.17	44.50	-	-	-	-	-
Currant Creek	27.88	21.60	22.50	20.89	20.51	26.60	34.07	36.94	37.29	36.84	32.50	33.90	34.18
Gadsby	38.66	37.65	38.36	37.39	-	-	-	-	-	-	-	58.66	-
Gadsby CT	47.16	37.78	39.68	38.95	43.03	52.82	-	72.65	73.27	-	-	-	66.57
Hermiston	33.95	32.60	32.30	32.56	32.19	33.72	33.32	33.77	34.32	33.47	36.61	42.07	38.81
Lake Side	26.11	20.15	21.07	19.89	19.48	24.41	31.52	33.69	33.65	33.16	29.60	30.14	31.17
Little Mountain	72.00	52.80	52.45	-	49.70	60.17	75.92	82.45	82.90	81.39	72.67	74.90	-
Total Thermal Resources	52.58	50.13	47.57	46.11	47.40	65.18	57.83	51.60	56.53	57.15	51.44	63.42	60.44

Staff/403
Dougherty/7

b. Bridger Coal is unregulated. It is theoretically capable of earning an unlimited rate of return. This could lead to a windfall to PP&L shareholders by PP&L ratepayers.

c. The original base price of $3.75 may not have been reasonable. The actual costs of Bridger Coal may not bear a close relationship to indices used to adjust coal price.

The staff's ideal coal price would be one permitting Bridger Coal to recover expenses and earn a fair and reasonable rate of return. Staff would allow a 10.06 percent rate of return via a $7.07 per ton coal price on sales to PP&L.

Staff's repricing of PP&L coal purchases is based on the theory that a corporation should not be permitted to fragment a utility enterprise by use of affiliated corporations and thereby obtain an increased rate of return for its activity. <u>See Pacific N. W. Bell v. Sabin, 21 Or. App. 222, 534 P.2d. 984 (1975), rev. denied</u>.

Staff believes this is what PP&L is doing in the case of Bridger Coal. However, the effect of staff's adjustment is to hold Bridger Coal's <u>equity return rate</u> equal to the equity return rate staff recommends for PP&L.

3. Company's Position

The company maintains it is not bound by the terms of the <u>Sabin</u> decision. It argues that there are significant differences in its relationship with Bridger Coal Company and Pacific Northwest Bell's relationship with Western Electric Company because: (1) The investment in Bridger Coal was substantially more risky than a utility investment, and (2) Unlike the telephone affiliates, an alternate market exists for coal sold to PP&L at a price higher than the price charged PP&L ratepayers. The company asserts that the $7.78 price is reasonable because it is below a current fair market price for Bridger Coal -- $15.00.

4. Discussion

The company provided no figures to refute staff's calculation that Bridger Coal's return on investment at the $7.78 sales price would be 18.06 percent, or that its return on common equity would be 36.80 percent. The company acknowledges

CASE: UE 207
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 404

Exhibits in Support of Surrebuttal Testimony

<u>REDACTED VERSION</u>
August 25, 2009

STAFF EXHIBIT 404

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
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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 25th day of August, 2009.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
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