PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

September 4, 2009

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, Suite 215
Salem, OR 97310-2551

Attn: Filing Center

Re: UE 207 – PacifiCorp's 2010 Transition Adjustment Mechanism (TAM)
PacifiCorp's Sur-surrebuttal Testimony and Exhibits

PacifiCorp (dba Pacific Power) submits for filing an original and five copies of its Sur-surrebuttal Testimony and Exhibits.

PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

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

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

Please direct informal correspondence and questions regarding this filing to Joelle Steward, Regulatory Manager, at (503) 813-5542.

Very truly yours,

Andrea L. Kelly/R

Andrea L. Kelly
Vice President, Regulation
Enclosures

cc: UE 207 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 4th of September, 2009, I caused to be served, via E-Mail and overnight delivery (to those parties who have not waived paper service), a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

SERVICE LIST
UE-207

G. Catriona McCracken (C) (W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
catriona@oregoncub.org

Gordon Feighner (C) (W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
gordon@oregoncub.org

Robert Jenks (C)(W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
bob@oregoncub.org

Irion A. Sanger (C)
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
ias@dvclaw.com

Randall J. Falkenberg (C)
PMB 362
8343 Roswell Road
Sandy Springs, GA 30350
consultrfi@aol.com

Jason W. Jones (C)
Department of Justice
Regulated Utility & Business Section
1162 Court St, NE
Salem, OR 97301-4096
Jason.w.jones@state.or.us

Kevin Higgins (C) (W)
Energy Strategies LLC
215 State Street, Suite 200
Salt Lake City, UT 84111-2322
khiggins@energystrat.com

Katherine A. McDowell (W)
McDowell & Rackner PC
520 SW Sixth Ave, Suite 830
Portland, OR 97204
Katherine@mcd-law.com

Joelle Steward (C) (W)
Pacific Power & Light
825 NE Multnomah, Ste 2000
Portland, OR 97232
Joelle.steward@pacificorp.com

Jordan A. White (W)
Pacific Power & Light
825 NE Multnomah, Ste 1800
Portland, OR 97232
Jordan.white@pacificorp.com

Oregon Dockets (W)
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Kelcey Brown (C)
Oregon Public Utility Commission
P.O. Box 2148
Salem, OR 97301
Kelcey.brown@state.or.us

Peter J. Richardson (C) (W)
Richardson & O'leary
PO Box 7218
Boise, ID 83707
peter@richardsonandoleary.com

Greg Bass (W)
Sempra Energy Solutions LLC
101 Ash Street HQ09
San Diego, CA 92101
gbass@semprasolutions.com

Ariel Son

Ariel Son
Coordinator, Administrative Services

Exhibit PPL/111
Gregory N. Duvall

Docket No. UE-207
Exhibit PPL/111
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-surrebuttal Testimony of Gregory N. Duvall

September 2009

Q. Are you the same Gregory N. Duvall who has previously testified in this proceeding?

A. Yes.

Purpose and Summary of Testimony

Q. What is the purpose of your Sursurrebuttal Testimony?

A. I first discuss the adjustment that the Company has accepted in order to narrow the issues in dispute. I then provide an overall perspective on the Company's proposed level of net power costs ("NPC") in this case. Finally, I discuss the key remaining issues in the case and respond to Commission Staff's ("Staff") and the Industrial Customers of Northwest Utilities' ("ICNU") testimony on these adjustments.

Q. Is PacifiCorp presenting any other sursurrebuttal testimony?

A. Yes. Company witnesses Mr. A. Robert Lasich and Mr. Bret C. Morgan are filing Sursurrebuttal Testimony responding to Staff witness Mr. Michael Dougherty's Surrebuttal Testimony on coal issues.

Q. Please summarize your testimony.

A. In my testimony, I:

- Agree to the parties' adjustment to include the Condit hydro facility for the entire test period;
- Show why the overall NPC level in this case is fair and reasonable, in comparison to the other cases cited by Staff, ICNU and the Citizens' Utility Board ("CUB");
- Show that Staff's and ICNU's proposed adjustments to hydro generation

are not supported by the record in this case;

- Demonstrate that ICNU's proposed elimination of market caps (now supported by Staff) are not justified by the disparity in actual and modeled sales and would greatly overstate coal generation;
- Show the technical and policy flaws of ICNU's many modeling adjustments, including daily vs. monthly screens, start-up energy, modeling long-term contracts and Cal ISO fees; and
- Address Staff's and ICNU's incorrect interpretations of the TAM Guidelines and refute the related adjustments.

Condit Adjustment

Q. Has the Company agreed to accept any additional adjustments proposed by the other parties beyond those discussed in your Rebuttal Testimony?

A. Yes. While the Company believes its proposal relating to the Condit hydro facility is reasonable and consistent with the TAM Guidelines, the Company will agree to include Condit throughout the test year in order to reduce the areas of dispute between the parties. Staff, ICNU and CUB all propose that the Company include the Condit facility throughout the test year.

Q. How do you propose this adjustment be calculated?

A. While the Company concedes to the proposal to include the Condit facility throughout the test year, this adjustment should be calculated as all others are - by running the adjustment through the GRID model. While the final amount of the adjustment will not be known until the final GRID inputs are determined, I estimate that this adjustment will reduce NPC by approximately $0.7 million on a total-Company basis.

Q. Why didn't you calculate the Condit adjustment as Ms. Kelcey Brown proposes in Exhibit Staff/300, Brown/6, using the "Hydro Market Value" worksheet?

A. The Company creates the referenced worksheet to mark-to-market hydro for indicative analysis, not for ratemaking purposes. It does not account for the effects of system dispatch from running GRID. The only accurate way to calculate the value of this adjustment is to run the adjustment through GRID.

Q. Do you have any other proposals related to the Condit adjustment?

A. Yes. To ensure that the Company can recover prudently-incurred NPC related to the Condit decommissioning, the Company agrees to include Condit for a full year in future Oregon TAM NPC forecasts until it is actually decommissioned. This agreement is contingent upon the Company being allowed to defer for future recovery the incremental NPC amounts incurred between the time that Condit is decommissioned and subsequent Oregon TAM rates, excluding Condit, go into effect. This approach ensures that customers are not charged for additional NPC when Condit is in commission, and that the Company can recover the additional NPC incurred after Condit is decommissioned.

Overall Level of Net Power Costs

Q. Do parties make arguments in relation to the Company's overall level of NPC?

A. Yes. Staff and ICNU both cite the Company's recent Utah rate case filing as evidence that the Company's proposed NPC in this proceeding are too high. The Company filed NPC of $999 million in the Utah rate case with a test year ending June 2010. This is compared with the $1.095 billion filed by the Company in this proceeding with a test period ending December 2010.

Q. What are the driving factors behind the difference in NPC in these proceedings?

A. As noted by Staff and ICNU, both of the test periods include the first six months of 2010. Reviewing the data during those six months shows that there are specific and justifiable reasons why the NPC forecasts differ in the two cases. First, and most significantly, the first six months of the TAM filing reflects a change in coal extraction at the Deer Creek mine that is not included in the Utah filing and that increases NPC. As discussed in the sursurrebuttal testimony of Mr. Morgan, this is attributable to the postponement of an outage of the longwall from the spring of 2010 to the fall of 2010. While this schedule change does not decrease overall 2010 test year costs for Deer Creek coal, the postponement of the outage to the fall means that the outage is not reflected in the Utah test period.

The TAM Guidelines do not allow the Company to make adjustments in the Rebuttal Update for the Company's captive coal operations, so the Company's Rebuttal Update did not reflect this change. In addition, coal costs included in the NPC calculations are averaged over the test period. As a result, the coal costs in the TAM for the overlapping six-month period of January through June 2010 are based on the average coal cost over calendar year 2010, while the coal costs in that same six-month period in the Utah general rate case are based on the average coal costs for the 12 months ending June 30, 2010.

Q. Is this issue relevant to any specific adjustments by the parties?

A. Yes. ICNU argues that the Company made a mistake in its assumptions for the Huntington Plant and proposed an adjustment in the amount of $19.3 million on a total Company basis. Mr. Randall J. Falkenberg simply assumed that because the Company's Utah filing did not contain this expense, it was in error in the TAM. As explained by Mr. Morgan, the Commission should reject ICNU's adjustment to Huntington coal costs because the difference between the Utah filing and the TAM results from the difference in test periods. Huntington coal costs are properly reflected in the TAM.

Q. Are there other differences between the Company's recent Utah NPC forecast and the forecast in this proceeding during the first six months of 2010?

A. While the Huntington coal cost issue accounts for about two-thirds of the difference between the two filings, there are other reasons for the difference. The Utah rate case includes two wind resources—Rolling Hills and McFadden Ridge—that the TAM does not. These resources serve to decrease NPC by approximately $7 million on total Company basis in the Utah rate case. The use of different forward price curves because of the timing of the two filings—the June 30, 2009 forward price curve in the TAM versus the March 31, 2009 forward price curve in the Utah rate case—also contributes to the difference in NPC calculations in the two filings. In sum, the difference in NPC between the

Company's Utah filing and this case is not an indication that the Company's TAM filing is overstated, as Staff and ICNU have alleged.

Key Issues in Dispute

Hydro Adjustments

Q. What are the hydro adjustments that remain in dispute?

A. Staff continues to argue that the Company has underestimated the output of the Bear River, J.C. Boyle, and Toketee hydro systems. ICNU also continues to support its proposed adjustment related to the Bear River and now supports Staff's adjustments to J.C. Boyle and Toketee.

Q. Did CUB propose adjustments to the level of hydro generation in this proceeding?

A. Yes. In reply testimony, CUB proposed an adjustment to the overall level of hydro generation in addition to its proposed adjustment to Condit generation that I discussed earlier in my testimony. Based on CUB's surrebuttal testimony, however, it appears that CUB is no longer contesting the overall level of hydro in the Company's filing.

Q. Has Staff presented any additional substantive arguments concerning the modeling for Bear River in Ms. Brown's Surrebuttal Testimony?

A. No. Staff continues to mischaracterize the Company's proposal for normalization of Bear River hydro as a short-term adjustment for drought and in particular, mischaracterizes the Company's response to Staff Data Request 60. The response to OPUC 60 (Staff/103, Brown/8) explains how the long-term drought conditions impact the operational constraints for flood control. Staff, however, has not disputed the fact that Bear River is different from the Company' s other hydro projects in the Pacific Northwest because the water available for generation at Bear River is dependent on contractually specified irrigation and flood control releases from Bear Lake. The usual manner of normalizing hydro over long periods of time is an appropriate way to model the Company' s hydro facilities in the Pacific Northwest that are not subject to significant contractual controls over discharge of water that can be used for generation. It is not, however, the only factor that is appropriate for Bear River, where contractual obligations prevent the Company' s hydro facilities from receiving any increased water releases from Bear Lake for flood control under normal hydro conditions.

Q. Does Staff dispute the facts presented by the Company as they relate to Bear River?

A. No. Staff does not dispute that (1) there has been a long-term drought in the area, which has resulted in a low elevation at Bear Lake, (2) flood control releases from Bear River have not been available for over a decade, (3) contractual obligations prevent the Company from operating Bear River in flood control mode unless Bear Lake reaches a certain elevation, and (4) there is no reasonable possibility that Bear Lake will reach that elevation during the test year or for the foreseeable future given normal water conditions. Despite this evidence, Staff continues to recommend that the Company model flood control releases in its calculation of NPC in 2010. Moreover, Staff' s implication that because the Company did not reflect this constraint in UE 199, it should not be allowed to do so here is misplaced. I addressed this in my rebuttal testimony, PPL/104, Duvall/16.

The Company requests that the Commission recognize the specific modeling needs of facilities of the Bear River as described by the Company and reject Staff's adjustment, as it is not supported by the facts.

Q. Does Staff continue to propose other hydro adjustments?

A. Yes. Staff continues to object to the level of hydro included in the filing for J.C. Boyle and Toketee. Staff, however, presents no new evidence or substantive arguments to support their claim. In effect, Staff is proposing that the Company model its hydro using the single-year median, except that the Company apply the three exceedence level modeling from UE 199 for certain facilities—and only for facilities that will result in a decrease to power costs. The Company should consistently use the single-year median to model hydro related to all hydro facilities. If the single-year median is appropriate to use where hydro has increased since UE 199, such as in the case of facilities on the Lewis River, it is appropriate to use where hydro has decreased.

Q. Has ICNU taken a position on Staff's proposed adjustments related to J.C. Boyle and Toketee?

A. Yes. ICNU now supports Staff's adjustments to Toketee and J.C. Boyle. ICNU's support for modeling hydro related to these facilities using the three exceedence levels used in UE 199 is puzzling given ICNU's strenuous objections to this modeling method in the previous TAM and in other jurisdictions. Mr. Falkenberg's agreement with Staff appears to be based on the fact that Staff's proposal would decrease NPC. The Company adopted the single-year median hydro method, which ICNU had advocated, because it is a straightforward method and the Company hoped its adoption would eliminate a significant contested issue among the parties. The Commission should allow the Company to use the single-year median method for all hydro facilities and reject the selective adjustments by Staff and ICNU.

Market Caps

Q. What is Staff's position on the market caps proposed by ICNU?

A. Staff now supports ICNU's proposed elimination of market caps, based upon a disparity in modeled and actual sales during graveyard hours.

Q. Are Mr. Falkenberg and Ms. Brown correct that the difference in modeled versus actual sales demonstrates new market liquidity sufficient to eliminate market caps?

A. No. The difference between the GRID result of 2.0 million MWh and the 4.6 million MWh in "actual sales" is not a new phenomenon and does not indicate an increase in market liquidity in light load hours. The Commission previously recognized the difference between actual sales and sales modeled in GRID in UE 191 in addressing Staff's proposal to impute a margin on PacifiCorp wholesale market sales:

> It is undisputed that GRID underestimates the volume of short-term wholesale transactions. As Pacific Power explains, an hourly deterministic production dispatch model like GRID will always underestimate the volume of short-term transactions, because it balances loads and resources and optimizes the system with perfect foresight. Order No. 07-446 at 10.

In other words, because the GRID model has perfect foresight, there is a disparity between the level of actual sales and those modeled in GRID. This disparity is not new and does not demonstrate a fundamental change in market liquidity to justify removal of the market caps.

Q. Does the difference between modeled and actual sales volumes imply that GRID is understating revenues and overstating NPC?

A. No. The Commission found in UE 191 that the understatement of actual short-term sales did not justify a margin adjustment because the bulk of the sales were system balancing transactions, on which PacifiCorp did not earn a margin. See Order No. 07-446 at 10-11. It is inconsistent with this ruling to now eliminate market caps and substantially decrease NPC on the basis of the disparity between actual and modeled short-term sales in GRID.

Q. In responding to Mr. Falkenberg's argument in support of market caps, you cited the fact that Mr. Falkenberg's adjustment would overstate coal generation. Does he respond to your argument?

A. Yes. Mr. Falkenberg states that I have presented an "exaggerated, misleading and otherwise meaningless comparison."

Q. What is the basis for your comparison?

A. I followed the reasoning of the 2004 ruling approving the Company's market caps by the Wyoming Public Service Commission, the only commission to explicitly rule on the Company's market caps, to structure my analysis. The Wyoming Commission found that the same market caps methodology used by the Company in this proceeding was appropriate because without the caps, modeled coal generation would exceed the actual four-year rolling average of such generation. Order, WYPSC Docket 20000-ER-03-198 (Feb. 28, 2004). Mr. Falkenberg testified against the market caps in Wyoming and selectively cited to materials filed at the Wyoming Commission in his testimony in this case. It is inconsistent for him to fail to acknowledge that I followed the Wyoming Commission's approach when I conducted my analysis.

Q. Why is the level of coal generation important in setting NPC?

A. The variable cost of coal generation in the Company's portfolio is nearly always substantially lower than market prices included in GRID. The higher the level of coal generation included in NPC, the lower NPC will be. Including an unreasonably high level of coal generation will artificially decrease power costs.

Q. Is the level of coal generation impacted by changes in load as asserted by Mr. Falkenberg and Ms. Brown?

A. No. The Company's coal generation is not correlated to load as Mr. Falkenberg and Ms. Brown suggest. Since 2000, the Company's loads have grown substantially, while its coal generation levels have not. As shown in PPL/112, the Company's most recent 12-month average of coal generation is less than the 12-month average ending in February 2000.

Q. Both Mr. Falkenberg and Ms. Brown assert that the Company's four-year averages are dated and argue that more recent 12-month comparisons should be used instead. How do the Company's and Mr. Falkenberg's proposed levels of coal generation compare with recent actual generation?

A. As shown in PPL/112, the Company consistently models more coal generation in its normalized NPC than it actually generated. Mr. Falkenberg's proposal to remove the market caps increases this overstatement in coal generation, resulting in a test period level of coal generation higher than any actual level the Company has experienced since 2000, except for late 2007 and early 2008 when availability spiked for a short period. Mr. Falkenberg' s proposed level of coal generation (modeled at the top of this spike) is significantly higher than any four-year average since 2000. Mr. Falkenberg' s proposal is also higher than virtually all one-year rolling totals since 2000, including the most recent one-year rolling totals. In fact, Mr. Falkenberg' s proposal exceeds the most recent one-year rolling total by 1.7 million MWh. This chart demonstrates that the market caps are necessary to prevent artificial increases in coal generation and a systematic understatement of NPC.

Q. Mr. Falkenberg claims that the Company uses market caps in a selective and self-serving manner, applying them in setting NPC in rates and QF prices, but not in the resource planning and acquisition process. Please respond.

A. The Company consistently applies market caps in using the GRID model. It does not use market caps in its model for resource planning and acquisition (the PAR model) because that model is differently designed and applied. The model has a more restrictive topology which results in lower coal generation levels than GRID. Additionally, resource planning and acquisition is typically focused on periods of peak demand, so the proper function of the model during graveyard hours in less important in the application of the PAR model.

Daily vs. Monthly Screens

Q. Has ICNU presented additional testimony in support of its proposal to implement daily screens?

A. Yes. Mr. Falkenberg incorrectly claims that GRID is affected by daily variations in load, market prices, and resources, and therefore daily screens are required. He also attempts to explain the shortcomings in his screens that I identified in my Rebuttal Testimony.

Q. Is Mr. Falkenberg correct that GRID is affected by daily variations in loads, market price, and resources?

A. No. Mr. Falkenberg did not address the facts that were included in my Rebuttal Testimony on this point. NPC in GRID are modeled assuming that the load, market price and resource availability and costs are perfectly known at the beginning of the test period and never change throughout the year. In operating the system on a real-time basis, as opposed to in an optimization model with static inputs, system operators have to process new information continuously, which requires them to incur costs that would not have been incurred had they been able to have perfect foresight. Use of daily screens without accounting for other daily operating costs that are not captured in GRID is unreasonable. The monthly screens proposed by Mr. Falkenberg in UE 199 and used by the Company in this docket reduced NPC by " over $25 million" in UE 199 as stated by Mr. Falkenberg in his Surrebuttal Testimony.

Q. Does Mr. Falkenberg use an example to support his argument on whether daily variations affect GRID?

A. Yes. On page ICNU/200, Falkenberg/18, Mr. Falkenberg presents a figure showing the daily dispatch benefits for Lake Side and the associated start-up costs based on data for May 2010. In the example for the month of May 2010, the Company did not include screens for Lake Side. On page ICNU/200, Falkenberg/21, Mr. Falkenberg notes that the Lake Side plant does not require screens in his study in any month. Yet the example purports to replace the Company screens in May 2010 with his screens. If both the Company and Mr. Falkenberg determined that screens were not required on the Lake Side plant in May 2010, the example should have shown no difference. He concludes from his example that the results of applying his daily screening method to GRID does not seem like a large amount of money.

Q. Do you have any other general observations about Mr. Falkenberg's proposal for screening gas-fired generating plants?

A. Yes. It is a moving target. Mr. Falkenberg has proposed monthly screens in prior dockets, partially developed daily screens in his reply testimony in this case, modifications to his daily screens in his surrebuttal testimony to correct "shortcomings" identified by the Company, and a promise for changes to come. In this case, Mr. Falkenberg argues against the monthly screens that he argued for in prior cases.

Q. What is your recommendation regarding the use of screens in GRID?

A. I recommend the Commission adopt monthly screens as being reasonable for the reasons set out in the Company's testimony in this docket.

Start-Up Energy

Q. What does Mr. Falkenberg discuss in his surrebuttal testimony related to start-up energy?

A. Mr. Falkenberg responds to my arguments in support of excluding start-up energy from NPC, arguing that the lack of an intra-hour market for energy and the fact that the Company will not back down coal generation or transact in the market while the gas units are ramping are "mutually contradictory."

Q. Does Mr. Falkenberg dispute that start-up energy is produced within the hour and that there is not an intra-hour market for electricity?

A. No. Yet his proposed approach is to allow start-up energy to be sold in inter-hour markets. This seriously overstates any value that would be associated with start-up energy. Given these undisputed facts, Mr. Falkenberg's proposal is flawed and should be rejected.

Q. What does Mr. Falkenberg purport to show in the figure on ICNU/200, Falkenberg/24?

A. Mr. Falkenberg claims that the figure shows that days where gas units started do not show any large spikes in regulating margin allocations. Mr. Falkenberg incorrectly concludes that the result to be drawn from the figure is that ramping up of gas units does not create the need for more reserves as I discussed in my Rebuttal Testimony.

Q. Does the figure provide useful information about the impact of a start-up sequence on reserves?

A. No. Even Mr. Falkenberg states that the differences are likely because the gas-fired units were already running on days when loads were higher. There are a number of other concerns with the figure because it averages all days when Currant Creek and Lake Side had start ups on one line ("NO Start"), and all other days on the other line ("CC LS Start"). These are then displayed using 24 points for each line representing the average hourly regulating reserve margin during 2008. This approach of displaying information is suspect since it does not offer any detail about load levels, day of the week, generation level of other resources, or other variables that could be used to explain the results. This chart should be given no consideration.

Q. On page ICNU/200, Falkenberg/24, Mr. Falkenberg purports to have quantified the impact of the Company's arguments concerning reserves, intra hour markets and other concerns. Is his quantification realistic?

A. No. The only change he made was to increase operating reserves, which are meant to cover the risk of forced outages and represent only 7 percent of the gas plant generation. This seriously understates the amount of resource that needs to be held in reserve to ramp down while the gas plant is ramping up, or to ramp up while the gas plant is ramping down.

Long-Term Contract Modeling

Q. Does Mr. Falkenberg agree with the Company that the approach to modeling both long-term wholesale sales and purchases in GRID should be done in a consistent manner?

A. No. He continues to insist on using differing approaches for long-term contracts based on whether the Company is buying or selling. Specifically, he unfairly proposes to use actual data to shape wholesale sales contracts when the Company is the seller, while using GRID optimization when the Company is the buyer. With regard to wholesale sales, he states that the best and least ambiguous data to which the Company has access are the actual delivery patterns. He gives no rationale why this is not also true for wholesale purchases.

Q. Is the use of actual historical delivery patterns of wholesale sales contracts a reasonable basis to determine the delivery patterns of these contracts in GRID?

A. No. They should be modeled using the GRID optimization logic like wholesale purchase contracts are modeled. Historical shapes are influenced by entirely different data than is expected to exist in the forecast test period. For example, market prices, resource availability, and loads all have an impact on how the buyer schedules to receive power under the wholesale sales contracts. It is not reasonable to assume that the operating environment that the buyers faced in the historical period would be replicated in the test period.

Q. How does Mr. Falkenberg respond to the Company's analysis on the SMUD contract that shows his proposal is not reasonable?

A. He bases his rebuttal on a new and unsubstantiated claim that the 20-year old SMUD contract is entirely imprudent. This appears to be his sole argument as to why the Company's analysis is not reasonable.

Q. Please comment on the figure shown on ICNU/200, Falkenberg/30 regarding the wholesale sales contract with the Public Service Company of Colorado ("PSCO").

A. After claiming that the Company's analysis of the PSCO contract is distorted, he presents his own distorted view of the historical numbers and inappropriately uses actual historical delivery patterns as a yardstick to measure accuracy. He gives no reason why this is a reasonable way to make a comparison, except that his modeling shows smaller errors. It is not clear why Mr. Falkenberg would not simply recommend using the actual historical data rather than average historical data, in which case the absolute error would be zero. The conclusion Mr. Falkenberg derives from this analysis should not be relied on because he has not shown that the analysis is sound and measures "accuracy" against an inappropriate source.

Cal ISO Fees

Q. What is ICNU's position on Cal ISO fees?

A. ICNU continues to recommend removal of all Cal ISO fees that the Company legitimately incurs in providing service to customers. This proposal reduces net power costs by over $11 million, total company.

Q. What would be the consequences if the Commission were to deny recovery of Cal ISO fees?

A. Accepting ICNU' s adjustment would be tantamount to telling the Company that it should not do business in the Cal ISO. The Company believes that such a result is poor regulatory policy and that the Commission should reject the proposed adjustment.

Q. Has ICNU raised any new arguments to support their position that the Company should not be allowed to collect legitimate costs that are incurred when doing business with the Cal ISO?

A. No. As I mentioned previously, the GRID model calculates NPC with perfect foresight and is very different from actual operations, which requires the Company to continuously balance its load and resources with economical means available to the Company at the time. If the GRID model does not have sales or purchase transactions as extensive as presented in actual data, it does not mean that those sales and purchase transactions, together with the expenses, would not be incurred.

Q. Has the Company verified the validity of the $11 million with more recent data?

A. Yes. In response to ICNU Data Request 12.59, the Company provided actual Cal ISO fees through May 2009. For the 12-months ending May 31, 2009, the Cal ISO fees were slightly higher than the $11 million included in the Company' s NPC study.

Short-Term Firm Transmission

Q. Has Mr. Falkenberg changed his approach to adjusting short-term firm (“ STF”) transmission?

A. Yes. He has attempted to eliminate the portion of STF transmission expenses that may be related to ancillary services or other elements that are not directly related to transfer capacity or transaction volumes from his adjustment. The amount subject to adjustment is about $5.7 million. The remainder is unadjusted from the 12-months ending June 2008 data used by the Company.

Q. How much of the $5.7 million is disallowed under Mr. Falkenberg’ s proposal?

A. As shown in Confidential PPL/113, Mr. Falkenberg removes all but a maximum of $0.4 million of the $5.7 million, allowing the Company to recover only seven percent of the $5.7 million. In addition, the $0.4 million is only 12 percent of the four-year average expense of $3.5 million for the four-year period ending December 2008. Mr. Falkenberg does not contest that these costs were prudently incurred.

Q. Why is Mr. Falkenberg’ s adjustment so big?

A. He uses a variable ($/MWh) charge to compute these expenses using GRID. This approach ignores the fact that STF expenses are incurred on a take-or-pay basis. His misuse of a variable charge results in significantly understating STF transmission expense.

Q. Mr. Falkenberg states that this is exactly the way you stated STF transmission modeling should be performed in the 2008 Utah case. Is he correct?

A. No. This statement, like the adjustment itself, is incorrect.

Scope of TAM Guidelines: Other Revenue, Biomass Contract and GP Camas

Q. What adjustments by the parties raise the issue of the scope of the TAM Guidelines?

A. Staff's proposed adjustments to Other Revenues and ICNU's proposed adjustment to the Biomass contract and Georgia Pacific ("GP") Camas raise issues of scope. Ms. Brown's and Mr. Falkenberg's testimony indicate that the parties have major disagreements on the scope of the TAM Guidelines that were not apparent to the Company until Staff and ICNU served their surrebuttal testimony in this proceeding.

Q. How does Staff's proposed Other Revenue adjustment show that the parties disagree about the scope of the TAM Guidelines?

A. Staff argues that updating the TAM for Other Revenues is consistent with the TAM Guidelines, even though Other Revenue is not a category listed as one that is subject to update.

Q. Prior to the TAM Guidelines, how did the Commission treat Other Revenues in stand-alone TAM proceedings?

A. In UE 191, the Commission addressed whether Other Revenue was subject to update in a stand-alone TAM. The issue arose in the context of ICNU's proposal to include Other Revenue associated with the GP Camas contract in the TAM. In

Order No. 07-446, the Commission agreed with PacifiCorp that ICNU's proposed adjustment was "outside the scope of the TAM proceeding," and that the Commission did not intend the TAM to include factors such as contract offsets that are better suited to a general rate case.

Q. How did the TAM Guidelines change this outcome?

A. Under the TAM Guidelines, Other Revenues is not included in Attachment A that lists the FERC accounts used consistently by the Company in defining NPC, which are updated in the TAM. However, the parties agreed in Section A.2 of the TAM Guidelines that the Company will update the steam revenues associated with Little Mountain Steam Sales, which are tracked in the Other Revenue account. The Guidelines do not include any other elements of Other Revenue that will be updated in the TAM. There is no reasonable way to interpret the Guidelines as allowing the TAM to include Other Revenues, except for Little Mountain Steam Sales.

Q. How do you respond to Staff's point that the Guidelines do not explicitly prevent Staff from proposing additional Other Revenue accounts that are appropriate to update?

A. Staff's interpretation of the Guidelines is contrary to the intent of the Guidelines as represented to the Commission by all the parties to the Guidelines. The parties, including both Staff and ICNU, represented to the Commission that the Guidelines provide the parties and the Commission specific parameters governing future TAM filings and that the goal of the Guidelines is to reduce disputes among the parties in TAM proceedings. *See* Joint Explanatory Brief, UE 199. If the Guidelines do not limit the parties from proposing updates that are not included in the Guidelines as being eligible to update, there is no point in having Guidelines to begin with. The Company is concerned that if the Commission agrees with Staff's interpretation, the Guidelines will be rendered meaningless.

Q. What else in the parties' testimony indicates that the Parties dispute the scope of the TAM Guidelines?

A. Mr. Falkenberg states in his testimony that "the limitations in the TAM Guidelines apply only to the Company," and therefore the Biomass and GP Camas adjustment proposed by ICNU should be adopted. ICNU apparently believes that PacifiCorp agreed to limit its ability to propose updates to the TAM, but agreed there would be no limits on updates proposed by other parties.

Q. Is this what the Company understood as the agreement between the parties?

A. Absolutely not. It was always clear that the trade-off for Staff and the intervenors in limiting the scope of TAM updates was that they would be potentially foregoing updates that could decrease NPC. To now argue that the update limitations asymmetrically apply only to NPC increases proposed by the Company, and not NPC decreases proposed by the parties, is inconsistent with past Commission precedent such as UE 191, which applied limitations on the scope of the TAM symmetrically. See Order No. 07-446 Nowhere in the Guidelines does it state that the limitations on updates described in the TAM apply only to Company proposals. ICNU's interpretation ignores the intent of the Guidelines. There is no basis within the TAM Guidelines themselves for ICNU's interpretation and the interpretation is contrary to the assumed cooperative spirit in which the parties negotiated the Guidelines. ICNU's interpretation jeopardizes the Company's support for these Guidelines and, more generally, the cooperation that is necessary to avoid extensive litigation before the Commission.

Q. What does this mean for the Biomass contract and GP Camas adjustments?

A. As I stated in my Rebuttal Testimony, the TAM Guidelines allow updating only for "known contracts," which is reasonably interpreted as executed contracts. The Biomass contract is not eligible for update under the TAM Guidelines because the Company does not have a signed contract. Similarly, the GP Camas adjustment is based on an update that is not included in the scope of updates allowed by the TAM Guidelines.

Miscellaneous Issues

Q. Please respond to the remaining issues.

A. The Company's response to new issues or arguments in the parties' surrebuttal is as follows:

- <u>Call Option Purchases</u> – No party has challenged the prudence of these expenses. If these expenses are disallowed by the Commission, the Company will have a strong disincentive to pursue these prudent resources in the future.
- <u>Non-Firm Transmission</u> – Mr. Falkenberg indicates that Utah requires the Company to include non-firm transmission in GRID. As this Commission is well aware, another Commission's action does not bind this Commission. ICNU has presented no reasonable basis for changing Commission policy on this issue.
- <u>Cholla Capacity Adjustment</u> – Mr. Falkenberg does not refute that his proposed adjustment to Cholla capacity ignores physical transmission constraints at the

Cholla interconnection making a portion of the increased capacity unusable.

- Long Hollow Wind – Mr. Falkenberg continues to recommend that the Commission deny the Company' s its prudently incurred costs associated with interconnecting new wind facilities to its system. The Company does not have the option to refuse interconnection with new facilities.
- Duct Firing Screens – At ICNU/200, Falkenberg/43, Mr. Falkenberg states that the Company's screen applied to the Currant Creek duct firing unit " was a crude and completely erroneous solution," because it forces the duct firing unit to be offline every day for two hours in a month. Mr. Falkenberg' s conclusion is incorrect. The duct firing screens only apply to Sundays and holidays in that month when the screens were needed. The Company' s duct firing screens do not need to be " fixed" .

Q. Are there certain of ICNU' s adjustments that the Company would be unable to implement should the Commission accept them?

A. Yes. In a number of instances, the workpapers provided by ICNU to support its adjustments are not consistent with what Mr. Falkenberg proposes in his written testimony. This further undermines the validity of the proposed adjustments and potentially creates a scenario where the Company would be unable to implement the adjustments if adopted by the Commission. For example, Mr. Falkenberg states that his screening adjustment for the combined cycle plants' starts with "reversing the Company screens." (ICNU/200, Falkenberg/21). However, based on his workpapers, he only partially reversed the Company's screens, and the logic of his screens is unclear.

Q. Does this conclude your sursurrebuttal testimony?

A. Yes.

Docket No. UE-207
Exhibit PPL/112
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

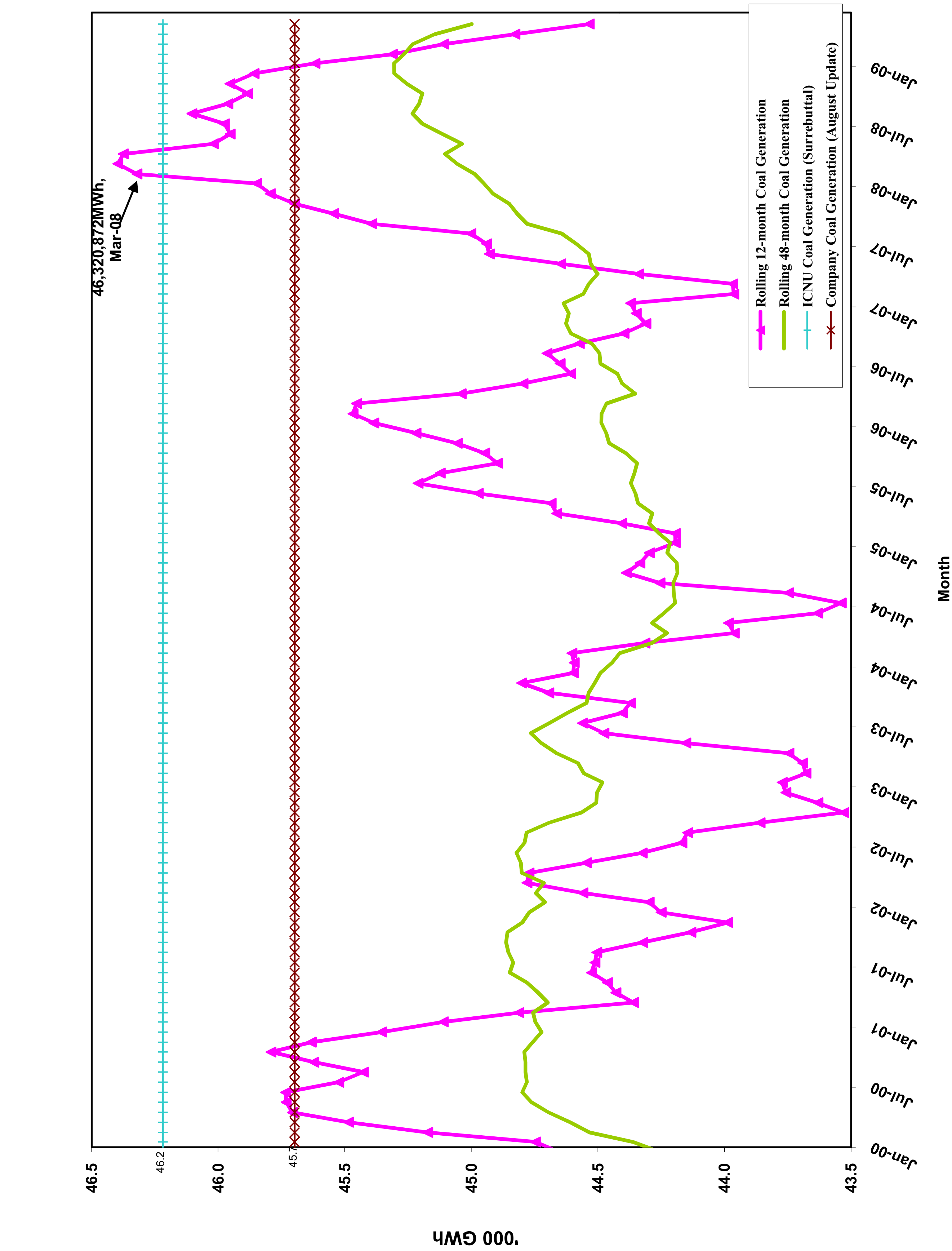
OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-surrebuttal Testimony of Gregory N. Duvall

Impact of ICNU Market Cap Adjustment on Coal Generation in GRID

September 2009


46,320,872MWh,
Mar-08
Rolling 12-month Coal Generation
Rolling 48-month Coal Generation
ICNU Coal Generation (Surrebuttal)
Company Coal Generation (August Update)
'000 GWh
46.5
46.2
46.0
45.7
45.5
45.0
44.5
44.0
43.5
Jan-00
Jul-00
Jan-01
Jul-01
Jan-02
Jul-02
Jan-03
Jul-03
Jan-04
Jul-04
Jan-05
Jul-05
Jan-06
Jul-06
Jan-07
Jul-07
Jan-08
Jul-08
Jan-09
Month

CONFIDENTIAL
Docket No. UE-207
Exhibit PPL/113
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Sur-surrebuttal Testimony of Gregory N. Duvall

Short-Term Firm Transmission Adjustment

September 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-207
Exhibit PPL/202
Witness: A. Robert Lasich

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-surrebuttal Testimony of A. Robert Lasich

September 2009

Q. Are you the same A. Robert Lasich who has previously testified in this proceeding?

A. Yes, I am.

Purpose and Summary of Testimony

Q. What is the purpose of your sur-surrebuttal testimony?

A. The purpose of my testimony is to respond to policy issues raised by the adjustments to the Company's coal costs proposed by Staff of the Public Utility Commission of Oregon ("Staff") and supported by Industrial Customers of Northwest Utilities ("ICNU") and Citizens' Utility Board of Oregon ("CUB").

Q. Please summarize your testimony.

A. My testimony addresses the following points:

- I demonstrate that the Company's approach to managing cost increases related to Emerging Issues Task Force ("EITF") 04-6 is a fair and balanced approach. This is in contrast to Staff's approach, which claims the benefit of the accounting standard when it reduces costs, but proposes to disallow recovery when it increases costs.
- I discuss the structure and regulation of coal supply contracts from the Energy West contract ("EWMC") for the Deer Creek mine and the Bridger Coal Company ("BCC") contract and explain why this eliminates the risk of cross-subsidization and refute the policy justification for Staff's "lower of cost or market" adjustments.
- I show that the costs of Huntington coal supply from EWMC and the costs of Bridger coal supply from the BCC are reasonable and explain why Staff's

line item adjustments to these costs are based on erroneous assumptions and should be rejected.

EITF 04-6

Q. Has the Company filed a request for an accounting order in Oregon to effectively negate the impacts of EITF 04-6 in its 2010 TAM coal supply costs?

A. Yes. The Company has requested an accounting order from the Commission in time to allow the final TAM update to reflect this proposed accounting treatment, resulting in an effective price for 2010 Bridger coal supply that approximates 2009 levels. The effect of the accounting order is to reduce cost volatility and mitigate harm to either the customers or the Company associated with the implementation of EITF 04-6.

Q. Has Staff testified that this accounting order is unnecessary?

A. Yes. Staff's view is that the accounting order is unnecessary. Staff indicates that it intends to review coal supply costs annually in the TAM using its newly proposed "lower of cost or market" standard. Staff indicates that it plans to recommend disallowance of all EITF 04-6-related cost increases if EITF 04-6 causes coal supply costs to rise above its definition of market. At the same time, if EITF 04-6 causes costs to decrease below market, Staff will recommend that customers get the full benefit of these cost decreases.

Q. Does Staff acknowledge the asymmetrical nature of its position?

A. Yes. Staff justifies the lack of fairness and balance in its position by asserting that the Commission's "lower of cost or market standard" is not symmetrical.

Q. Is it appropriate regulatory policy to apply an admittedly asymmetrical approach to the BCC contract, in the absence of any evidence of cross-subsidization?

A. No. As I discuss below, the cost-based nature of the BCC contract and the Commission's pervasive regulation of BCC's operations means that customers have no risk of being harmed under the contract. In fact, customers have enjoyed significant benefits over the years associated with the BCC contract. Indeed, in approving the BCC contract in Order No. 01-472, the Commission noted that from 1990 through 1999, the average cost of coal provided under the Agreement was $3 to $9 per ton less than the average market price of Southern Wyoming coal delivered to the plant. The contract also provides an important hedge against rising costs in the market and potential disruptions in deliveries that might be caused by rail transportation issues. In Staff's report on its pre-rate case audit in this case, dated March 11, 2009, Staff observed that "As a result of potential rising costs, having captive mines may result in an increasing benefit to PacifiCorp customers." PPL/203. The fundamental inequity of Staff's asymmetrical proposal is further highlighted when these past and future benefits are taken into consideration.

Q. Has the Commission previously approved an agreement to smooth BCC costs similar to what the Company is proposing in its EITF 04-6?

A. Yes. In Order No. 05-1050, the Commission approved a Stipulation, including a three-year amortization of costs associated with the development of underground operations at the Bridger mine. The Stipulation allowed the Company to recover these extraordinary but necessary costs at Bridger in a manner that smoothed and limited the rate impact.

Scope of Review of EWMC and BCC Costs

Q. Do you agree with Staff's statement that OAR 860-027-0048 affirms the Commission's transfer pricing policy "for ratemaking purposes"?

A. No. I have been advised that OAR 860-027-0048 addresses accounting, not ratemaking. *In re PacifiCorp*, Order No. 05-1050, Docket UE 170. I have also been advised that the Commission has followed a "reasonableness" standard in reviewing approved affiliate transactions for ratemaking purposes. *In Re PacifiCorp*, Order No. 91-513, UI 105 ("Through the rate-making process, the Commission can ensure that customers do not pay unreasonable expenses for affiliate transactions."); *In re PacifiCorp*, Order No. 02-820, UE 134/UM 1047 ("[T]he Commission does not establish the ratemaking treatment of the contract in the affiliated interest docket. However, the subsequent ratemaking review is whether the payments set forth in the contract are reasonable.")

Q. Mr. Michael Dougherty asserts that customers are "clearly subsidizing" EWMC and BCC based upon his conclusion that costs from these mines are higher than market. Do you agree with Mr. Doughtery that his adjustment is justified because customers are cross-subsidizing EWMC and BCC coal supplies?

A. No. In approving the EWMC contract, the Commission recognized that the atypical nature of the Company's agreement with Deer Creek makes cross-subsidization highly unlikely:

> EWMC was established in a manner so that it will not earn a profit. It is unlikely that a third party could provide services at a lower cost. …EWMC shall bill Pacific only actual costs for its service. This cost-based approach and the limitation of EWMC's activities to those arising under the contract minimize the likelihood of cross-subsidization. *In Re PacifiCorp*, Order No. 91-513, UI 105.

Similar to EWMC, the nature of the cost-based contract between BCC and PacifiCorp negates the possibility of cross-subsidization and the justification for Staff's adjustment.

Q. Has the Commission consolidated EWMC and BCC with PacifiCorp for regulatory purposes?

A. Yes. The Commission has followed a general policy of consolidating EWMC and BCC with PacifiCorp for regulatory purposes. *In re Pacific Power and Light Company*, Order No. 84-898, UE 21. This is evident in the inclusion of a review of EWMC and BCC costs in the PacifiCorp pre-rate case audit. PPL/203. It is also evident in the Staff's line item adjustments to EWMC and BCC costs proposed in this case.

Q. Has the Commission previously found that the pervasive regulation of subsidiaries subject to consolidation eliminated the possibility of cross-subsidization?

A. Yes. Under this consolidation policy, I understand that the Commission has previously found that there is no possibility of cross-subsidization. An order involving Idaho Power, PacifiCorp's partner at BCC who consolidates in the same manner, expressly makes this finding:

> Separate records and accounts for IERCO are maintained and the operations of IERCO as a joint venturer in Bridger are subject to regulatory review and scrutiny together with those of Idaho during

> general rate cases. The operations of IERCO are summarized in Idaho's semiannual reports of operations filed with the Public Utility Commission. IERCO's results of operations have been merged, consolidated, and included with Idaho's for the purposes of filing of income tax returns and for rate-making purposes. Therefore, there is no danger of cross-subsidization between Idaho and IERCO, nor is there any danger of Idaho paying in excess of market value to IERCO or its assignees for the coal purchased. Idaho is paying for its coal the same as if IERCO were not even involved in this transaction. Further, the coal sales agreements have and will continue to provide a reliable source of low-cost coal for the operation of the Jim Bridger plant. …The transfer price for the coal which is provided by Bridger to Idaho shall be billed at actual cost. Cost in this case is equivalent to market for the services. Since all of IERCO's results of operation are merged with and made a part of Idaho's for rate making, there is no possibility of cross-subsidization. *In re Idaho Power*, Order No. 91-567, UI 107.

Q. Do these same points address CUB's position in support of the Staff's adjustments at Huntington and Bridger?

A. Yes. CUB argues that these adjustments are necessary to prevent the utility and its affiliate from increasing profits to its utility holding company by overcharging customers. However, since the contracts with EWMC and BCC require these entities to credit profits back to PacifiCorp in the cost-based price and since the Commission regulates the costs of EWMC and BCC, CUB's concern that customers are being overcharged is not warranted.

Huntington Plant Fuel Burn Expense Adjustment (Staff and ICNU)

Q. Are the costs of Deer Creek coal supply to Huntington reasonable?

A. Yes. As Mr. Bret C. Morgan testifies, the costs compare favorably when fairly compared to current, available market alternatives. Additionally, Staff's analysis concludes that the price at Huntington is over market, but not the price at Hunter. In response to the rebuttal testimony of Mr. Morgan questioning this arbitrary result, Staff acknowledges that the difference is a " timing issue concerning coal delivery." In other words, Staff admits that the differences between costs at Huntington and Hunter are <u>not</u> associated with cross-subsidization at Huntington. The Company could have changed the delivery schedules in 2010 by transferring tonnage in higher production cost months to Hunter, which would have dramatically reduced the Staff's adjustment. Such an approach, however, would have been inconsistent with the overall least cost supply to both plants. Without evidence of the possibility of cross-subsidization, there is no policy justification for Staff's Huntington adjustment.

Q. Are Staff's line item adjustments for labor and other miscellaneous costs appropriate?

A. No. There are several flaws in Staff's analysis. First, Mr. Dougherty incorrectly cites $9,311,000 as Management/Supervisory Wages for 2010. This amount is not solely management wages but includes benefits, overtime and bonuses as well.

Q. Are there other deficiencies with Mr. Dougherty's analysis?

A. Yes. Mr. Dougherty's analysis does not address that $262,000 in Deer Creek Mine management wages were cross-charged to BCC in 2008. Deer Creek Mine management have been supporting BCC's underground mining operations. With Deer Creek management's assistance BCC has improved continuous miner productivity and planning of longwall moves thereby benefiting the ratepayers. There is no budgeted cross-charge in 2010.

Q. Are there other issues with Staff' s analysis?

A. Yes. Mr. Dougherty removes 50 percent of management overtime and bonuses. The management overtime cost in the 2010 budget is $319,000. The front line supervision component of this amount is $149,000 - ensures adequate management supervision on all union shifts. The remaining $170,000 in management overtime pay is paid out only after a management employee has worked 12 overtime shifts through the year or as holiday pay. Also, in determining their adjustment Staff incorrectly applies an inflation rate of (-) 1.9 percent for 2009. This negative escalation rate in 2009 is inconsistent with the Staff' s treatment of the labor portion of operation and maintenance costs in the General Rate Case. Management wages and benefits were not reduced in 2009 due to Global Insight' s projection of a negative CPI.

Q. Have you prepared an exhibit with the above corrections?

A. Yes. As reflected in Confidential Exhibit PPL/204, of the total Oregon-allocated costs for these categories of $2.2 million, the corrected adjustment is $234,310, one-third of the Staff calculation of $616,260. PacifiCorp believes that the costs of EWMC are reasonable, however, and that no adjustment is warranted even at the corrected, reduced level.

Staff' s Bridger Plant Fuel Burn Expense Adjustment

Q. Are the costs for Bridger coal supply reasonable?

A. Yes. Staff contends that BCC' s costs are significantly higher than nonaffiliated costs. My direct testimony explained why costs have increased at Bridger. My rebuttal testimony also explains that the increase in costs in 2010 at Bridger is due almost exclusively to implementation of EITF 04-6. Mr. Morgan' s rebuttal testimony demonstrates that, notwithstanding these increases, Bridger coal costs remain reasonable and competitive with available nonaffiliate alternatives.

Q. Please respond to Staff' s line-item adjustments.

A. Mr. Dougherty' s proposed line item adjustments total $632,990. Mr. Dougherty includes an adjustment of $358,804 for management wages without ever considering the budgeted increase in BCC workforce.

Q. Please explain the change in BCC' s workforce.

A. In 2008, there was an average of 82 exempt employees. The 2010 budget reflects 103 exempt employees.

Q. Why is the workforce increasing?

A. Through 2008, due to the limited housing market in Rock Springs, as well as the lack of workforce availability, BCC experienced difficulty in attracting and retaining employees. BCC recruited from outside the southwest Wyoming area for experienced management employees, but the lack of affordable housing, as well as the demand from the oil and gas operations, resulted in significant turnover. BCC retained Price Mining Services, an outside contractor with expertise in both surface and underground mining, to support both the surface and underground mining operations. Starting in 2010, Price Mining Services will no longer provide contract support for BCC.

Q. Do BCC' s costs reflect a reduction in outside services between 2008 and 2010?

A. Yes. Outside services, including the management roles that will be filled by additional employees, will decrease from $8.364 million to $5.962 million, a reduction of $2.4 million.

Q. Are there other issues with Staff's analysis?

A. Yes. Mr. Dougherty removes 50 percent of management overtime and bonuses. The management overtime cost in the 2010 budget is $296,598. At BCC, only front line supervision is paid overtime. Front line supervision ensures adequate management supervision on all scheduled union shifts. Similarly to Deer Creek, Staff incorrectly applies an inflation rate of (-)1.9 percent for 2009. This negative escalation rate in 2009 is inconsistent with Staff's treatment of the labor portion of operation and maintenance costs in the general rate case in UE 210. Additionally, an adjustment for fines and citations is inappropriate – fines and citations were removed from the 2010 BCC budget.

Q. Have you prepared an exhibit with the above corrections?

A. Yes. As reflected in Confidential Exhibit PPL/205, of the total Oregon-allocated costs of $1.9 million for these categories, the corrected adjustment is $18,122 as compared to the Staff calculation of $632,990. PacifiCorp believes that the costs of BCC are reasonable, however, and that no adjustment is warranted even at the corrected, reduced level.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UE-207
Exhibit PPL/203
Witness: A. Robert Lasich

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-surrebuttal Testimony of A. Robert Lasich

Excerpt of Staff Audit Report
March 11, 2009

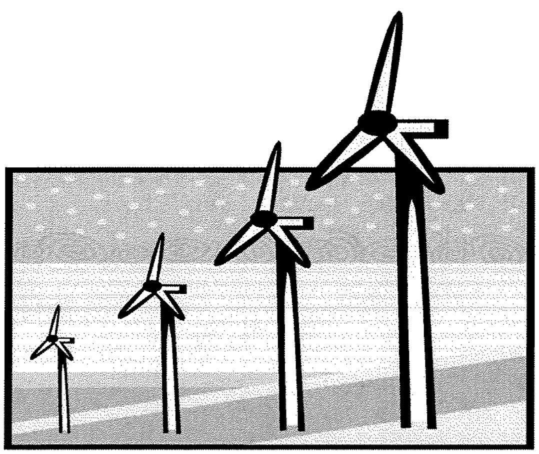
September 2009

Staff Audit Report of

PacifiCorp

Audit Number: 2008-002

March 11, 2009



Audit team: Dustin Ball (Lead Auditor)
Michael Dougherty
Marion Anderson

Prepared by: Dustin Ball

Corporate Services/Cost Allocation Manual

Pursuant to OAR 860-027-0048, PacifiCorp provided Staff a Cost Allocation Manual (CAM) as an attachment to its 2007 Affiliated Interest Report. Staff reviewed the content and format of the CAM and believes that PacifiCorp has adequately addressed its cost allocation methods.

Coal Purchases from Affiliates

PacifiCorp purchases coal from certain affiliates, Bridger Coal Company, Energy West Mining Company, and Trapper Mining Company. The Bridger Mines provides coal to the Jim Bridger plant, of which PacifiCorp owns 66.7 percent. The Jim Bridger plant is located in Wyoming. According to the Company, the transition of Jim Bridger Coal Company from surface mining operation to a combined underground/surface mining operation has resulted in an increase in costs and a shift in cost drivers. As a result in the change in operation, coal costs from Jin Bridger have increased.

Energy West Mining Company's Deer Creek Coal Company (underground mining method) provides coal for the Company's Carbon, Hunter, and Huntington Plants, which are located in Utah. According to PacifiCorp, coal costs have increased from 2006 to 2008 due to a number of factors including labor and benefit costs, materials and supplies, mine maintenance, and professional services.

PacifiCorp is also a minority owner of Trapper Mining Inc. (21.4 percent). Trapper Mining Inc. provides coal to PacifiCorp's Craig Plant, which is located in Colorado. According to PacifiCorp's 10-K, the Craig Plant is supplied from coal produced from a surface mining operation.

The following tables shows Bridger Coal Company (Underground/Surface), Deer Creek Coal Company (Underground), and Trapper Mining Coal Company (Surface) coal costs for 2006 through 2008. The table also for illustrative purposes shows coal costs for PacifiCorp coal plants not supplied by affiliates. Unless specified, the coal costs do not include transportation costs.

Table 25 – Coal Costs, 2006 - 2008

	2006	**2007**	**2008**	**Change 2006 - 2008**
Coal Purchased from Affiliates				
Bridger Coal – Wyoming (Combined)	$20.77	$23.59	$29.37	41.41%
Deer Creek Coal – Utah (Carbon, Hunter, Huntington - Underground)	$23.93	$26.27	$25.08	4.81%

Trapper Coal Base – Colorado (Craig - Surface)	$22.68	$24.43	$25.57	12.74%
Trapper Coal Spot – Colorado (Craig - Surface)	$22.50	$20.60	$29.88	32.8%

Coal Purchased from Third Parties				
Coal supplied to Cholla - Arizona (Surface)	$24.05	$24.24	$27.52	14.43%
Dave Johnston – Wyoming (Surface)	$5.34	$5.83	$7.14	33.71%
Dave Johnston – Wyoming with Transportation	$9.99	$10.52	$12.09	21.02%
Wyodak – Wyoming (Surface)	$10.59	$10.81	$11.49	8.50%
Naughton – Wyoming (Surface)	$25.04	$27.46	$26.86	7.27%
Colstrip – Montana (Surface)	$14.46	$15.80	$17.27	19.43%
Hayden – Colorado (Combined)	$31.38	$33.43	$34.03	17.27%
Hayden – Colorado with Transportation	NA	NA	$36.80	NA

The following table highlights market prices.

Table 26 - DOE/EIA 2007 Info Average sale price ($ per Short Ton)

State	2006 Underground	2006 Surface	2007 Underground	2007 Surface
Colorado	$24.10	$24.70	$24.91 (Total)	Not listed
New Mexico	$29.15 (Total)	Not Listed	$29.91 (Total)	Not listed
Utah	$24.98	Not listed	$25.69	Not listed
Wyoming	Not Listed	$9.03	Not Listed	$9.67 (Open) 13.62 (Captive)

** Information received from PacifiCorp based on Platt's indicates that 2008 average Colorado coal price was $34/ton, a significant increase from the 2007 level. Additionally, 2008 average Utah coal price was $28.41, also a significant increase from the 2007 level.*

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

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

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

Table 27 – Heat Content of Coals used by PacifiCorp Plants

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

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

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

The article also points out:

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

> PRB coal is the world's cheapest source of electricity," said Dan Scott, director of equity research at investment bank Dahlman Rose. "In today's market, that creates interesting opportunities for miners and the railroads hauling the coal.

As a result of potential rising costs, having captive mines may result in an increasing benefit to PacifiCorp customers. This is not a foregone conclusion and costs and cost trends would need to be examined during subsequent rate filings.

Transfer Pricing

Commission orders concerning affiliated interest contracts with Bridger (Order No. 01-472, UI 189) and Energy West (Deer Creek, Order No. 91-105, UI 105) allow for cost-based pricing of coal from these affiliates. This is an approved departure from OAR 860-027-0048, Allocation of Costs by an Energy Utility, which normally requires the lower of cost or market standard when a utility is purchasing goods or services from an affiliate.

ORS 757.495, Contracts involving utilities and persons with affiliated interests, requires the Commission to approve the contracts if the Commission finds that the contracts are fair and reasonable and not contrary to the public interest. In both the Bridger and Energy West contracts, the Commission found that the contracts were fair and reasonable and not contrary to the public interest.

However, concerning approval of affiliated interest contracts, the Commission does not need to determine the reasonableness of all the financial aspects of the contract for ratemaking purposes. The Commission can reserve that issue for a subsequent proceeding. The subsequent proceeding in this case would be the Company's TAM or general rate filing.

Concerning transfer pricing in UI 189, Staff's memo states:

> If there should be a further lowering of the savings to PacifiCorp and its customers, it may necessitate a modification to the transfer price to meet the Commission's AI policy. This would then require PacifiCorp to comply with proposed ordering condition No. 3 to protect the public's interest.

Deer Creek Mine

Based on a comparison, the average 2007 market price in Utah (underground) of $25.69 was lower than PacifiCorp's coal costs concerning Deer Creek underground ($26.27). However; as previously mentioned, the 2008 Deer Creek cost of $25.49 reflects a decrease in costs from the 2007 level resulting in slightly lower than market levels ($25.69). If 2008 Deer Creek costs are actually determined to be below market and maintained at below market, this would result in a benefit to customers.

Trapper Mining

Concerning Trapper Mining, the 2007 market price for total operations in Colorado ($24.91) is higher than the Trapper Mining 2007 cost for base ($24.43) and spot ($20.63) purchases. Additionally, 2008 third-party coal costs for PacifiCorp's Hayden Plant in Colorado was significantly higher ($34.03) than the Trapper Mining 2008 cost for base ($25.57) and spot ($29.88) purchases. As a result, Trapper Mining costs actually appear are clearly below market cost, which results in a benefit to customers.

Bridger Coal

As previously mentioned, Bridger is a combined surface/underground mining operation. The following table highlights the change in operation of Bridger from a predominantly surface operation to a predominantly underground operation from the 2006 through 2008 time period.

Table 28 – Bridger Mining Operations

	2006	2007	Through September 2008
Surface Operations – Tons (000)	5,646.0	3,139.4	1,745.0
Surface Operations - $/Ton	$18.490	$18.354	$24.467
Underground Operations – Tons	422.3	2,644.9	2,471.8
Underground Operations – $/Ton	$51.24	$29.812	$34.185

The 2008 Bridger combined underground/surface cost ($28.34) as well as underground cost ($34.19) are comparable to the 2008 underground mining for Utah ($28.4) and Colorado ($34.00). The Bridger 2008 surface coal cost ($24.467) is considerably higher than two other PacifiCorp's Wyoming plants (Dave Johnston ($12.09 with transportation), Wyodak ($11.49), but actually lower than coal cost at Naughton ($26.86). It should be noted that Bridger is located in Southwest Wyoming's Green River Basin (GRB). According to information furnished by PacifiCorp, there are only three coal mines operating in the GRB.

Additionally, it should be noted that PacifiCorp Bridger costs are higher than the Wyoming overall market costs. Unfortunately, because Bridger is the only underground mining operations in Wyoming, comparative cost studies can not be made for Wyoming underground operations. In addition, Bridger coal is mined from GRB and requires a higher heat content than PRB coal, which also affects any straight cost comparison.

Because PRB coal is the next logical coal supply for Bridger, associated transportation costs to transport PRB coal to Bridger could possibly make this option economically infeasible. With that said, the affiliated interest statute allows for a review of costs that go into rates.

As a result, rate case staff should examine 2008 comparable coal costs to determine if the 2008 Bridger costs are in the range of 2008 comparable underground mining costs for the GRB region. If Bridger costs show a trend of exceeding comparable market costs, staff may be required to review the transfer pricing in UI 189 concerning Bridger in order to protect the public's interest.

In addition, during a rate case or TAM review, utility staff should recommend that Bridger coal costs be adjusted for the lower of cost or market for ratemaking. Again, the affiliated interest order concerning Bridger (Commission Order No. 01-472, UI 189) includes a condition that states:

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

Staff Recommendations:

10. Staff should examine 2008 comparable coal costs to determine if the 2008 Bridger costs are in the range of 2008 comparable underground mining costs for the Green River Basin region. If Bridger costs show a trend of exceeding comparable market costs, staff may be required to review the transfer pricing in UI 189 concerning Bridger in order to protect the public's interest. *(Further investigation during the rate case)*

11. In future filings, Staff should recommend that Bridger coal costs be adjusted for the lower of cost or market for ratemaking. *(Further investigation during the rate case)*

Review of Affiliate Coal Costs

Staff examined account line detail of affiliate coal costs. The following comments are relevant concerning PacifiCorp's coal costs included in rates.

Bridger Coal

Management/Supervisory Overtime

Bridger experienced a significant increase in Management/Supervisory overtime costs from $117,838 in 2006 to an annualized amount of $448,908 in 2008. Audit Staff is not aware of any recent rate orders that have allowed overtime for management/supervisory personnel. The Oregon-allocated amount equals approximately $80,499 ($448,908 x 66.67 percent x .268974 allocation). As a result of supervisory overtime costs, in future rate filings, assigned Staff should examine mining wage/salaries in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs

Bargaining/Temporary Overtime

Bridger experienced a significant increase in Bargaining/Temporary overtime costs from $6,866,573 in 2006 to an annualized amount of $10,537,424 in 2008 (57.3 percent). This 2008 overtime amount represented approximately 31 percent of Bargaining/ Temporary 2008 annualized total (regular plus overtime) pay. Bridger shifted from surface to combination underground/surface mining operation. As a result, Bridger increased full-time equivalents (FTE) from 288 to 353.

The following table examines FTE and regular/overtime wages for Bargaining/Temporary employees.

Table 29 – Bridger Bargaining/Temporary FTE and Wages (2008 Annualized)

		Per Employee
Total FTE	353	
Total Regular	$16,878,441	$47,814
Total Overtime	$10,537,424	$29,851
Total	**$27,416,218**	**$77,665**

As a result of the high overtime costs, in future rate filings, assigned Staff should examine mining wage/salaries in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Incentives

Bridger's 2008 annualized incentive costs equal approximately $878,067. Following the same methodology for ratemaking, Staff would recommend a 50 percent adjustment to incentives. The Oregon-allocated amount equals approximately $78,730 ($878,067/2 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine incentives in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Health Care Costs

According to PacifiCorp, Bridger Coal health care benefit programs target a 90/10 sharing arrangement for bargaining employees and programs ranging from a 90/10 to 74/26 for management employees. In the most recent energy utility rate case (UE 197), Staff recommended an 85/15 sharing of premium costs. Bridger's 2008 annualized health costs were $4,417,512. At an 85/15 sharing, these costs would be approximately $4,172,095. The Oregon-allocated amount equals approximately $44,009 ($245,417 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine health care costs in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Employee - Meals
Bridger experienced $43,564 (annualized to $58,085) in meals and entertainment expenses. During a rate case, Staff will normally recommend a 50 percent sharing between customers and shareholders. This is a fair approach that somewhat mirrors the policy associated with bonuses (50 percent sharing between customers and shareholders) and the handling of these expenses for income tax purposes. For income tax purposes, the amount allowable as a federal income tax deduction for business meal and entertainment is generally limited to 50 percent of the total expense. The Oregon-allocated amount equals approximately $5,208 ($58,085/2 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine meals in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Donations
Bridger's 2008 annualized costs for donations are approximately $2,933. These costs should be disallowed because the Commission has not allowed regulated utilities to recover contributions to charities, community affairs, and economic development organizations through rates charged for regulated services. These expenses are discretionary and are not required to provide safe and adequate service to customers. In addition, Commission policy does not require customers to support causes in which they do not believe.[10] The Oregon-allocated amount equals approximately $526 ($2,933 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine donations in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Fines and Citations
Bridger's 2008 annualized costs for fines and citations are $203,388. Customers should not be required to pay for fines and citations incurred by Bridger. The Oregon-allocated amount equals approximately $36,473 ($203,388 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine fines and citations in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

[10] OPUC Order 87-406 states at pp. 40-41, "Since community affairs expenditures are discretionary, the funds could be retained by the business's owners. . . .Owners of unregulated businesses, rather than their customers, make community affairs contributions." Also see Order 91-186 at 16.

Other O&M
Because of the change in operations, Bridger experienced increased costs in many O&M line items and incurred other costs not experienced during surface mining operations. Audit Staff recommends that during future rate filings, Staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs that should not be included in rates.

Staff Recommendations concerning Bridger costs:

12. In future rate filings, assigned Staff should examine mining wage/salaries, overtime costs, health care costs, incentive, donations, meals and entertainment, and fines in the same method as Company wages are analyzed during rate cases and make the appropriate adjustments to coal costs.

13. In future rate filings, assigned Staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs.

Deer Creek Mine

Staff examined account-line detail for the Deer Creek Operations. The following comments are relevant concerning PacifiCorp's coal costs in rates.

Management/Supervisory Overtime
Deer Creek experienced a significant decrease in Management/Supervisory overtime costs from $351,306 in 2006 to an annualized amount of $182,525 in 2008. Although this is a decrease in costs, Audit Staff is not aware of any recent rate orders that have allowed overtime for management/supervisory personnel. The Oregon-allocated amount equals approximately $49,094 ($182,525 x .268974 allocation). In future rate filings, assigned Staff should examine supervisory overtime in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Bargaining Overtime
Deer Creek experienced a increase in bargaining overtime costs from $2,350,962 in 2006 to an annualized amount of $2,526,102 in 2008. This 2008 overtime amount represented approximately 18.4 percent of Bargaining 2008 annualized total (regular plus overtime) pay. The following table examines FTE and regular/overtime wages for bargaining employees.

Table 30 – Deer Creek Bargaining FTE and Wages (2008 Annualized)

		Per Employee
Total FTE	278	
Total Regular	$11,217,881	$40,352
Total Overtime	$2,526,102	$9,087
Total	**$13,744,261**	**$49,439**

As can be seen from the above table, total pay of Deer Creek bargaining personnel ($49,439) is approximately 63.7 percent of total average bargaining pay of Bridger Coal ($77,655). This difference is primarily a result of lower overtime payments and reflects a considerable savings for ratepayers. In future rate filings, assigned Staff should examine mining wage/salaries in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Incentives

Deer Creek's 2008 annualized incentive costs equal approximately $1,230,000. Following the same methodology for ratemaking, Staff would recommend a 50 percent adjustment to incentives. The Oregon-allocated amount equals approximately $165,419 ($1,230,000/2 x .268974 allocation). In future rate filings, assigned Staff should examine incentives in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Health Care Costs

According to PacifiCorp, Deer Creek's health care benefit programs in 2007 and 2008 ranged from 85/15 to 80/20 cost sharing. The option of a 90/10 cost sharing arrangement for management employees was implemented in 2008. All other plans have a 74/26 cost sharing arrangement in 2008. In the most recent energy utility rate case (UE 197), Staff recommended an 85/15 sharing of premium costs. In future rate filings, assigned Staff should examine health care costs in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Meals and Entertainment

Deer Creek experienced $33,463 (annualized to $44,617) in meals and entertainment expenses. As previously mentioned, during a rate case, Staff will normally recommend a 50 percent sharing between customers and shareholders. The Oregon-allocated amount equals approximately $6,000 ($44,617/2 x .268974 allocation). In future rate filings, assigned Staff should examine meals in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Club/Organization Membership and Expense

Although Deer Creek had costs in 2006 and 2007 for this line item, PacifiCorp reported $0 for 2008. Normally, this is a cost item that staff would examine in more detail; however because there is no cost in 2008, a further review is not necessary. In future rate filings, assigned Staff should examine membership expenses in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Mining Services
In 2008, Deer Creek Mine experienced $2.33 million in mining services. According to PacifiCorp, these services are for major equipment overhauls performed away from the mine at vendor facilities. During PacifiCorp's subsequent rate filings these costs should be reviewed in detail to determine if some of these expenses are more correctly capitalized. This is because replacements and overhauls generally have the effect of increasing the service potential of an asset by either improving the asset's efficiency or extending the asset's economic useful life. As a result, the costs of replacements and overhauls are capitalized.[11]

Other O&M
Audit Staff recommends that during future rate filings, assigned staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs. Concerning Deer Creek, Audit Staff notes considerable increase in professional services, management fees, royalties, and fuel from 2007 to 2008.

Staff Recommendations concerning Deer Creek costs:

14. In future rate filings, assigned Staff should examine mining wage/salaries, overtime costs, health care costs, incentive, donations, meals and entertainment, and membership expenses in the same method as Company wages are analyzed during rate cases and make the appropriate adjustments to coal costs.

15. In future rate filings, assigned Staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs.

Trapper Mining
Because PacifiCorp is a minority owner of Trapper Mining, PacifiCorp did not have detailed line item costs for Trapper Mining. However, as previously mentioned, Trapper Mining costs were lower than the listed DOE/EIA 2007 market costs. As a result, PacifiCorp is actually receiving goods at the lower of cost or market.

Coal Transportation
PacifiCorp's Cholla, Dave Johnston, and Hayden Plant all received transported coal. The following table examines transportation cost per ton.

[11] Munter – Radcliffe, *Applying GAAP and GAAS, Depreciable and Intangible Assets*, Matthew Bender & Co., Inc. page 10-21.

Table 31 - Coal Transportation Costs

Plant	2006	2007	2008	Percent Change 2007 - 2008
Cholla – Arizona (Coal from New Mexico and Montana	$4.91*	$7.47	$7.97	6.69%
Dave Johnston – Wyoming (Coal from Wyoming)	$4.65	$4.68	$4.94	5.26%
Hayden – Colorado (Coal from Colorado)	NA**	NA	$2.76	NA

** Cholla's 2006 costs were significantly lower than subsequent years due to a $3 million credit applied to Cholla in January 2006.*

*** Prior to 2008, PacifiCorp did not separate transportation costs from coal costs at the Hayden plant.*

Because PacifiCorp's Cholla plant is located in Arizona, higher transportation costs would be reasonably expected. Because of the low cost of coal being supplied to the Dave Johnston plant ($7.14 in 2008), transportation costs actually account for approximately 40.4 percent of total coal costs. Even with transportation costs, the Dave Johnston plant had the second lowest 2008 coal costs for PacifiCorp plants at $12.07 per ton. Only the Wyodak plant, supplied by the Wyodak mine and not requiring transportation, had lower costs at $11.49 per ton.

As previously mentioned, PacifiCorp has two Commission approved affiliated contracts with Burlington Northern Santé Fe Railroad (BNSF). Berkshire-Hathaway currently owns 17 percent of BNSF. PacifiCorp has long-term coal transportation contracts with BNSF, including indirect payments to a generation plant that is jointly owned by PacifiCorp. The transportation contacts were approved by the Commission in Order No. 07-323 (UI 269), dated July 27, 2007. BNSF provides transportation services from:

1. Various coal mines in the Wyoming Powder River Basin to PacifiCorp's David Johnston Steam Plant (David Johnston); and

2. Various coal mines in Wyoming, New Mexico, and Montana to PacifiCorp's Cholla Generating Station (Cholla).

These agreements were executed as third-party agreements prior to PacifiCorp becoming a subsidiary of MEHC. This type of service is provided pursuant to a contract filed and approved by the Surface Transportation Board (STB)[12] would generally not require Commission approval; however, PacifiCorp and MEHC agreed to a different affiliate transaction standard as part of PacifiCorp's acquisition by MEHC. PacifiCorp pays approximately $30 million per year for services under the Agreements with BNSF. PacifiCorp records most of the charges related to the BNSF agreements in FERC Account 501, Fuel.

Operations and Maintenance Expenses

The following table presents O&M expenses (FERC accounts 500-598) for 2006 and 2007:

Table 32 - O&M Cost Comparison

	2006	2007	Percentage Change 2006-2007
Labor	123,864,786	100,446,457	-18.9%
Non-Labor	432,179,061	572,124,600	32.4%
Total O&M	556,043,847	672,571,057	21.0%

The overall increase is higher than the Consumers Price Index for All Urban Consumers of 2.8 percent for the period and is largely attributable to two areas – (1) higher gas costs and (2) plant additions. An account comparison was made and there were 15 instances of year-to-year variances greater than 10 percent. The company provided satisfactory explanations for these increases. The distortions due to singular accounting occurrences i.e. out-of-period charges were also itemized.

Customer Service

The company stated that there is a ten-year technology improvement plan. There are four current deliverables:

1. Customer correspondence improvement project – template improvement as to location and clarity.
2. Automated outage customer call back program – customizing notification and follow up service restoration.
3. Computer telephony integration and interactive voice response systems – symmetry between account information displayed online and phone accessible and multiple phone match screens.

[12] The Surface Transportation Board (STB) was created in the Interstate Commerce Commission Termination Act of 1995 and is the successor agency to the Interstate Commerce Commission. The STB is an economic regulatory agency that Congress charged with the fundamental missions of resolving railroad rate and service disputes and reviewing proposed railroad mergers. The STB is decisionally independent, although it is administratively affiliated with the Department of Transportation. (www.stb.dot.gov)

Exhibit PPL/204
A. Robert Lasich

CONFIDENTIAL
Docket No. UE-207
Exhibit PPL/204
Witness: A. Robert Lasich

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Sur-surrebuttal Testimony of A. Robert Lasich

Corrections of Staff' s Deer Creek Mine Miscellaneous Line Adjustments

September 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

CONFIDENTIAL
Docket No. UE-207
Exhibit PPL/205
Witness: A. Robert Lasich

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Sur-surrebuttal Testimony of A. Robert Lasich

Corrections of Staff’ s Bridger Coal Company Miscellaneous Line Adjustments

September 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-207
Exhibit PPL/402
Witness: Bret C. Morgan

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-surrebuttal Testimony of Bret C. Morgan

September 2009

Q. Are you the same Bret C. Morgan who has previously testified in this proceeding?

A. Yes, I am.

Purpose and Summary of Testimony

Q. What is the purpose of your sur-surrebuttal testimony?

A. The purpose of my testimony is to respond to adjustments to the Company's coal costs proposed by the witnesses for the staff of the Public Utility Commission of Oregon ("Staff"), Industrial Customers of Northwest Utilities ("ICNU") and Citizens' Utility Board of Oregon ("CUB").

Q. Please summarize your testimony.

A. My testimony addresses the following points:

- I demonstrate that the Company has properly reflected the costs of Dave Johnston coal supply in its TAM update, negating Staff's adjustment.
- I show that the costs of Huntington coal supply from Deer Creek are reasonable and should not be reduced under a "lower of cost or market" affiliated interest standard. I also explain why ICNU's allegation that the costs are overstated based upon a comparison to the Utah filing is mistaken.
- I demonstrate that the costs of coal from the Bridger Coal Company ("BCC") are reasonable and should not be reduced under a "lower of cost or market" affiliated interest standard. I explain that Staff's position to the contrary is based upon a failure to consider the actual availability of alternative coal supplies to the Bridger plant.

Staff's Dave Johnston Plant Fuel Burn Expense Adjustment

Q. Does Staff agree with PacifiCorp's position that Staff's adjustment for Dave Johnston has been resolved by PacifiCorp's TAM update, which updated costs based upon the results of the competitive bidding process for Dave Johnston market-based coal supply?

A. In part. Staff accepts the price of $9.86/ton, but contests whether PacifiCorp has properly reflected this update in its filing. Staff contends that the new price should have reduced Dave Johnston's costs by approximately $500,000 more than PacifiCorp reflected in its update.

Q. Please explain the difference between the Staff's calculation of the value of the update and PacifiCorp's.

A. First, PacifiCorp's calculations make the adjustments required by the differences in the heat content between the forecast and bid prices. The Company's original forecast price of $10.33/ton assumed a heat content of 8400 btu/lb. The updated price is based upon an average heat content of 8243 btu/lb for the two bids. As shown in PPL/403, the Company's update reflected 14,286 tons of additional coal necessary to compensate for the lower heat content; Staff's calculations omit this additional tonnage. Second, PacifiCorp's calculations reflect the August TAM update in the Black Hills contract that supplies Dave Johnston, while Staff's do not.

Q. Have you prepared an exhibit demonstrating the Company's calculation of updated Dave Johnston coal costs?

A. Yes. PPL/404 provides detail on the Company's calculation. This exhibit demonstrates that there is no basis for Staff's remaining adjustment to Dave Johnston coal costs.

Huntington Plant Fuel Burn Expense Adjustment (Staff and ICNU)

Q. Staff relied upon spot market prices for its original Dave Johnston adjustment. Staff did not use spot market prices for its Huntington adjustment, because it claims that long-term contract supplies are available to the Company. Do you agree with Staff's position?

A. No. Staff claims that there are six sources of non-affiliate coal supply in Utah; in fact, there are only four. If the Company were to move away from Deer Creek coal in favor of a new coal supply agreement, it would require the replacement of approximately 3.0 million tons of Deer Creek coal. This represents more than 13 percent of Utah's total estimated annual coal production. The Huntington plant will receive 2.659 million tons of the 3.0 million ton total from Deer Creek. Some portion of the alternative supply would have to be acquired from the spot market. Prices on the spot market remain at approximately $48 per ton, which is almost $20 more than Deer Creek's delivered cost.

Q. Staff claims that setting the market price for the Huntington plant as an average of the delivered coal cost to the Company's Huntington, Hunter and Carbon plants is fair. Do you agree?

A. No. This average price does not accurately capture current market prices for comparable coal supplies because it is comprised of contracts of different vintages related to coal supplies of varying qualities. The increase in long-term coal contract prices is dramatically illustrated by two contracts in Staff's average, the

Sufco contract from the late 1990' s at \$23.67/ton FOB mine and the Electric Lake contract from February 2008 at \$32.35/ton FOB mine, which is approximately 37 percent higher. If current contracts are used as the source for current market prices, then Deer Creek compares favorably (i.e. Electric Lake price plus transportation costs to Huntington is several dollars a ton higher than Deer Creek coal).

Q. Both Staff and ICNU argue that the Company reflected lower costs for Huntington in the pending Utah rate case than in this case. Please explain.

A. An outage to rebuild the longwall is now scheduled for the latter half of 2010. This outage is reflected in this case because it uses a calendar year 2010 test period, but not in the Company' s Utah rate case because the test period extends only through the first six months of 2010.

At the time of the initial filing in this case, the longwall outage was scheduled earlier in 2010 and the workpapers underlying the Company' s filing reflect this plan. The Company did not reflect this change in schedule in its TAM update because changes to captive mines are now excluded from the update under the TAM Guidelines. The change in the schedule of the longwall outage from early to late 2010, however, does not impact the overall coal supply cost in this case to the Huntington plant.

Staff' s Bridger Plant Fuel Burn Expense Adjustment

Q. What is PacifiCorp' s primary critiism of Staff' s market analysis that is the basis of Staff' s adjustment to Bridger Coal costs?

A. Staff' s analysis sets the market proxy price based upon two other coal supply transactions in the Green River Basin of Wyoming (Black Butte to Bridger and Kemmerer to Naughton), deeming these to be "available" coal supplies to Bridger without consideration of the terms, conditions and limitations on actual availability. Staff explains that "the focus should be on the cost of coal," without acknowledging that availability considerations directly impact such costs.

Staff's approach effectively reads the word "available" out of the rule. Staff then ignores as irrelevant PacifiCorp's unrebutted evidence that: (1) there are no additional supplies from the Black Butte mine and insufficient supplies at the Kemmerer mine available to PacifiCorp for 2010 coal supply at Bridger; (2) any additional supplies from the Black Butte mine would be available only at the 2010 Black Butte contract price, not the price that Staff uses reflecting 2009 carry-over tonnage; (3) coal from the Kemmerer mine is available to Bridger only if a transportation component is included,[1] which results in a price that is higher than BCC's; (4) the only alternative supplies that are available to meet Bridger coal supply needs are from the Powder River Basin and these are more expensive than BCC coal, including transportation to the Bridger plant.

Staff proposes an interpretation of the Commission's transfer rule that eliminates consideration of the real costs of alternative coal supplies. There is no apparent Commission precedent for this interpretation. There is also no justification for this aggressive approach in the absence of evidence of affiliate abuse or unreasonable costs.

[1] Naughton is mine-mouth at the Kemmerer mine, so the coal supply price does not reflect any material transportation component even though the price is a delivered price to the plant. In contrast, delivery costs between Kemmerer and Bridger would be considerable, given the distance of 120 miles between the two.

Q. Is PacifiCorp taking the position that customers should not benefit from the carryover tonnage in the Black Butte contract as alleged by Staff?

A. No. This credit is fully reflected in the Bridger costs in this case. Indeed, the older vintage 2009 carryover coal accounts for approximately 20 percent of the total tons to be delivered from the Black Butte mine. The price associated with the 2009 carryover tons represents just 43 percent of the 2010 effective contract price of Black Butte coal. The Company' s point is simply that if it could acquire additional supplies from Black Butte for 2010, the price would not reflect this credit, since the 2009 tonnage has been fully utilized in the existing contract. As I explained in my rebuttal testimony, the 2010 contract price for Black Butte is comparable to BCC' s 2010 price.

Q. Is Staff' s adjustment calculated correctly?

A. No. While Staff increased the size of its adjustment because the Company' s TAM update increased the cost of the Bridger plant coal supplies, Staff did not reflect the TAM update increases in the Black Butte and Kemmerer/Naughton contracts in the underlying calculation of its adjustment. If it had done so, this would decrease Staff' s adjustment by an additional $1,344,116 based upon updated Kemmerer and Black Butte costs. For purposes of this calculation, the costs associated with Black Butte assume that the total delivered costs include the carryover tonnage from 2009. If the carryover tonnage is not included, Staff' s adjustment would be an even a larger reduction. Staff' s proposed adjustment would be reduced by a total of $2,229,901. Exhibit PPL/405 illustrates these adjustment calculations.

Q. Staff suggests that if the Commission adopted the Company's position to review the overall price at Bridger instead of the individual components of the costs, Staff's adjustment would increase. Is this correct?

A. No. As I demonstrated in my rebuttal testimony, when the overall price of BCC coal is fairly compared to available market alternatives, there is no basis for any adjustment. Staff has not rebutted any of this analysis.

Q. Does this conclude your testimony?

A. Yes.

CONFIDENTIAL
Docket No. UE-207
Exhibit PPL/403
Witness: Bret C. Morgan

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Sur-surrebuttal Testimony of Bret C. Morgan

Analysis of Open Position for Dave Johnston

September 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

CONFIDENTIAL
Docket No. UE-207
Exhibit PPL/404
Witness: Bret C. Morgan

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Sur-surrebuttal Testimony of Bret C. Morgan

Calculation of Dave Johnston Coal Costs

September 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

CONFIDENTIAL
Docket No. UE-207
Exhibit PPL/405
Witness: Bret C. Morgan

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Sur-surrebuttal Testimony of Bret C. Morgan

Corrected Calculation for Staff’ s Lower of Cost or Market Analysis for Bridger

September 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER