PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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August 11, 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 Rebuttal and Update Filing

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

It is respectfully requested that all communications related to this filing be addressed to:

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

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

Very truly yours,

Andrea L. Kelly
Vice President, Regulation
Enclosures

cc: UE 207 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 11th of August, 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.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

PACIFICORP

DOCKET UE-207
2010 TRANSITION ADJUSTMENT MECHANISM (TAM)

Rebuttal Testimony and Exhibits

August 2009

Exhibit PPL/104
Gregory N. Duvall

REDACTED
Docket No. UE-207
Exhibit PPL/104
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Gregory N. Duvall

[REDACTED]

August 2009

Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power (the " Company").

A. My name is Gregory N. Duvall, my business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232, and my present title is Director, Long Range Planning and Net Power Costs.

Q. Have you previously filed testimony in this case?

A. Yes. I filed Direct Testimony in this case.

Q. What is the purpose of your testimony?

A. My testimony has two parts: a Transition Adjustment Mechanism (" TAM") update/corrections section and a rebuttal section.

First, in the TAM update section, I provide contract, fuel, and forward price updates to the Company' s net power costs. I also explain data corrections to the March filing. Parties in this case were previously notified of these corrections in a July 2, 2009 letter from the Company. Finally, I explain the reasonableness of the Company' s revised system NPC of $1.095 billion, a number that reflects the TAM update, corrections, and adjustments for the test period of the 12 months ending December 31, 2010.

Second, in the rebuttal section of my testimony I respond to the adjustments and criticism of the Company' s net power costs (" NPC") presented by Ms. Kelcey Brown on behalf of Commission Staff (" Staff"), Mr. Randall Falkenberg on behalf of the Industrial Customers of Northwest Utilities (" ICNU") and Messrs. Robert Jenks and Gordon Feighner on behalf of the Citizens' Utility Board (" CUB"). PacifiCorp witness Mr. Bret C. Morgan has filed rebuttal testimony responding to Mr. Michael Dougherty' s proposed adjustments to coal costs on behalf of Staff. Finally, PacifiCorp witness Mr. A. Robert Lasich has filed rebuttal testimony responding to ICNU' s proposed adjustment G.4. relating to the EITF 04-6 at the Bridger mine.

Recommendation for Company' s Net Power Costs for this Case

Q. In your direct testimony, you recommended that the Commission set the Company' s system NPC at $1.101 billion for the forecast year ending December 31, 2010. Has this overall recommendation changed?

A. Yes. The Company has reduced its recommended system NPC to $1.095 billion.

Q. Why have you decreased your system NPC recommendation to $1.095 billion?

A. Since I filed direct testimony on March 30, 2009 (" Initial Filing"), there have been three relevant developments. First, the Company updated the TAM filing with (1) the most recent forward price curve and (2) new power, fuel, and transportation/transmission contracts and updates to existing contracts in accordance with the TAM Guidelines adopted by the Commission in Order No. 09-274 in Docket UE 199. Second, the Company made corrections to and addressed omissions from the Initial Filing, also in accordance with the TAM Guidelines. Third, the Company received the testimonies of the Staff and interveners containing a number of adjustments to lower net power costs. As discussed below, the Company agrees that some of these adjustments are reasonable and disputes others. These factors result in an overall decrease to system NPC to $1.095 billion.

Q. Have you produced an exhibit that shows the derivation of the $1.095 billion system NPC?

A. Yes. Exhibit PPL/105 summarizes the cost impact of the TAM updates, data corrections, and adopted adjustments that result in a total company NPC of $1.095 billion.

Q. What is the increase in forecast NPC on an Oregon-allocated basis?

A. As illustrated in Exhibit PPL/106, on an Oregon-allocated basis, the Company's forecast normalized NPC for calendar year 2010 are approximately $272.4 million. This is a slight decrease from the Initial Filing and results in a NPC increase in 2010 of $5.6 million. The combination of the $5.6 million in increased net power costs and the $14.4 million of decreased revenues results in a total proposed revenue increase of $20.0 million.

Q. Would total Company NPC of $1.095 billion produce a reasonable result in this case?

A. Yes.

Q. Do you have any general observations about the level of NPC recommended by ICNU?

A. Yes. ICNU proposes NPC of $995 million. This is significantly lower than the level of NPC currently included in rates ($1.043 billion from UE 199), the Company's actual NPC for 2008 ($1.119 billion), and the Company's most recent actual NPC for the 12 months ending May 2009 ($1.055 billion).

Q. Are there any specific reasons that ICNU’ s NPC modeling results in NPC results that are so low?

A. Yes. One large driver is the unreasonably excessive amount of coal generation that results from ICNU’ s NPC modeling. Including an excessive amount of coal generation artificially decreases NPC. ICNU’ s results show the Company’ s coal plants generating about 1,364,087 megawatt hours above historic levels based on its partially finished screen runs (this difference would be higher if all the screens were finished). At an estimated $40 per megawatt hour margin, this results in an understatement of NPC by at least approximately $55 million.

Q. What input assumptions drive such unreasonable results?

A. ICNU’ s adjustments to remove graveyard market caps, add daily screening, add non-firm transmission and increase the capacity of Cholla to levels that exceed the physical transmission capability available to the Company all contribute to the increase in overall generation levels at the Company’ s coal plants. The reasonableness of the NPC outcome of ICNU’ s modeling should be a factor in judging the reasonableness of ICNU’ s input assumptions.

Q. How do the Company’ s NPC results for coal generation compare to actual coal generation?

A. Compared with the historical actual coal generation, the Company’ s modeled coal generation is 457,804 and 661,585 megawatt hours higher in its Initial Filing and August Update, respectively. In comparing to actual levels of coal generation, the Company relied on the average generation that occurred over the 48-months ending June 30, 2008, the same time period used to determine the forced and planned outage inputs for each coal unit. This shows that there is no basis to model a higher level of coal generation, as the amount currently modeled by the Company has not been understated.

NPC Updates and Corrections

Q. Please describe how the Company updated NPC.

A. The NPC in my rebuttal filing were updated to reflect the most recent official forward price curve dated June 30, 2009. This update includes prices for the indexed contracts, mark to market value of physical natural gas transactions and financial swaps, as well as reshaped hydro generation. The NPC were also updated to reflect new power, fuel, and transmission/transportation contracts and updates to existing contracts. Exhibit PPL/105 provides a summary of the impact on total Company NPC for each of the items.

Q. Why did the Company update NPC with the most recent official forward price curve and these contract data?

A. On July 16, 2009, the Commission approved the TAM Guideline Stipulation entered into by the parties to Docket UE 199 (the same parties to this proceeding). The TAM Guidelines govern future TAM proceedings and this proceeding, except to the extent the Guidelines expressly state they are inapplicable to this proceeding. Order No. 09-274 at Appendix A at 2. Section B of the TAM Guidelines describes the NPC components that will be updated in the Company's Rebuttal Update Filing. Order No. 09-274 at Appendix A at 2-3. The components include the most recent forward price curve and new power, fuel, and transportation/transmission contracts, and updates to existing contracts.

Q. Did the Company make any other updates to NPC?

A. Yes. Section B of the TAM Guidelines also provides that the Company may make corrections to or address omissions from the cost components included in the Initial Filing. Order No. 09-274 at Appendix A at 11. The impacts of the following corrections on total Company NPC are included in Exhibit PPL/105:

- Reserve capability under the Seattle City Light ("SCL") Stateline contract: The reserve capability provided by the SCL was inadvertently turned off when the Company switched from modeling the reserve requirements of SCL Stateline to modeling the reserve requirements of the entire Stateline project.
- Idaho Power purchase contract: The Company has corrected the historical information used for estimating the delivery of the contract.
- Hermiston currency exchange rate: The Canadian dollar to U. S. dollar exchange rate used for the Hermiston plant fuel cost was inverted.
- Currant Creek and Lake Side planned outages: Currant Creek's planned maintenance is based on a weighted average of historical data and the engineers' recommendation, given the short history of the plant. To be consistent with the application of the historical data for the combined cycle units, the engineers' recommendation that is used in the calculation should have been the maintenance of steam unit only. Because the planned outages for Lake Side are assumed to be the same as the ones for Currant Creek, the maintenance outage of the Lake Side plant is also updated as a result.
- Overlapping of planned outages: The planned outages of the Lake Side plant, Hermiston and Jim Bridger units contained overlapping days.

- Maximum regulating margin: The settings for regulating margin requirements were inadvertently changed from what were in UE 199.
- Duct firing operation: The duct firing units were on when the main units were offline.
- Inclusion of the Long Hollow wind facility as non-owned generation: The Long Hollow project should have been included in the determination of the reserve requirements of the non-owned generation that is located within the Company's control area.
- Startup costs, both dollar per startup and amount of gas required, of the Chehalis plant were incorrectly stated.

Overall, these corrections decrease total Company NPC by approximately $9.3 million.

Company Responses to Specific Adjustments – Overview

Q. How have you organized your responses to the parties' modeling adjustments to net power costs?

A. I have grouped the parties' proposed NPC modeling adjustments into three categories. First, there are adjustments to which the Company has agreed in whole. Second, there are adjustments to which the Company has agreed in part or in response to which the Company has proposed a compromise position. Third, there are proposed modeling adjustments that the Company disputes as inaccurate, unsubstantiated, or inconsistent with normalized ratemaking.

<u>Adjustments Accepted in Whole</u>

Q. Has the Company accepted any adjustments proposed by Staff, CUB, or ICNU?

A. Yes. The Company has accepted the following proposed adjustments:

- Staff proposes the removal of the additional O&M costs for plant start-ups and reduces total Company NPC by $1.2 million. ICNU also proposes this adjustment as ICNU adjustment B.2. By accepting this, NPC decrease by approximately $0.9 million on a total Company basis from the Company's Initial Filing.
- ICNU's Adjustment G.1 to correct the inputs for regulating margin requirements in GRID. This is one of the Company's corrections stated above. It results in a $3.0 million decrease to NPC on a total Company basis from the Company's Initial Filing.
- ICNU's Adjustment I.1 to account for the rest of the Company's corrections to NPC described above. The total impact on NPC of all the corrections, except the regulating margin requirements, result in a $6.2 million decrease to NPC on a total Company basis from the Company's Initial Filing.

<u>Adjustments Accepted in Part</u>

Condit Decommissioning

Q. Do parties recommend adjustments to the modeling of the Condit hydro facility?

A. Yes. Staff and ICNU propose a change to NPC to reflect the delay of the Condit decommissioning date from October 1, 2009 to October 1, 2010. However, both

Staff and ICNU propose not only that Condit be included in rates until the most recent decommissioning date of October 1, 2010, but through the entire test year. Staff proposes a $5.2 million decrease, and ICNU proposes a $3.7 million decrease to total Company NPC based on this change. CUB proposes a similar adjustment in the amount of $1 million total Company.

Q. What is the Company' s position on the Condit adjustment?

A. Similar to the update it agreed to last year, the Company agrees to reflect the current status of the Condit decommissioning in the TAM. The Company has not received all the necessary permits for it to begin the decommissioning process. Therefore, the Company agrees to reflect Condit being included in rates through September 30, 2010.

Q. Why doesn' t the Company agree to model Condit generation past October 1, 2010?

A. Extending the operation of Condit beyond September 30, 2010 is speculative. The only information available to the Company is that Condit will be decommissioned starting October 1, 2010. Using another date for the expected decommissioning would depart from the Commission' s known and measurable standard. If the Commission is going to use a more flexible known and measurable standard than it has in the past, it should apply that standard equally to cost components that increase NPC and those that decrease NPC.

Q. What is the impact of including the generation from the Condit project through September 30, 2010?

A. The update to the decommissioning date of the Condit project reduces NPC by approximately $3.0 million on total Company basis from the Company's Initial Filing. The Company calculated this amount by including the single-year median water value for Condit in the GRID model for nine months and recommends that any calculation of the value of adding Condit generation in 2010 should be based on using single-year median water values modeled in GRID.

ICNU Adjustment E.1 (Chehalis Modeling)

Q. Please describe ICNU's proposed adjustment to the capability of the Chehalis plant.

A. ICNU adjusts Chehalis's capability and claims that the Company's input was in error, lowering system NPC by $0.2 million.

Q. Do you agree with ICNU's adjustment?

A. No. The Company's inputs for the Chehalis plant in the Initial Filing were based on the best information available at the time of the study in the spring of 2009. In the response to Company's Data Request ("DR") 1.2 (see Confidential Exhibit PPL/107), ICNU states that Mr. Falkenberg made the adjustment based on data from the Company's filing in its Wyoming jurisdiction. Based on a stipulation with parties in the state of Wyoming in a prior proceeding, the Company froze the data for the study that Mr. Falkenberg referenced, at an earlier date, in July of 2008, based on the best information available at that time.

Q. Did ICNU indicate that it may accept a different modeling of the Chehalis plant's capability?

A. Yes. In its response to the data request, ICNU states that it would agree to the Company modeling Chehalis' [redacted] based on the information that was provided in the Company' s workpapers supporting the Company' s Initial Filing, " if the Company believes it to be correct when the[redacted]."

Q. How has the Company updated the Chehalis capability in the current filing?

A. The Chehalis plant is located in the control area of Bonneville Power Administration (" BPA"). Whether the plant ca[redacted] is impacted by the operations of the BPA' s transmission system. Based on the agreement with BPA, the Company expects to be able to [redacted] on the Chehalis plant no sooner than March 2010. Prior to that date, the Chehalis plant can not [redacted]. However, in this update the Company assumed the capability would be available at the beginning of the test period. This update reduces NPC by approximately $39,412 on a total Company basis after Company' s corrections and updates.

ICNU Adjustment E.2 (Mountain Wind Qualifying Facility)

Q. Did ICNU recommend an adjustment to the Company' s modeling of the generation from the Mountain Wind qualifying facility projects?

A. Yes. ICNU' s Adjustment E.2 reduces the generation from the Mountain Wind Qualifying Facility. ICNU' s adjustment results in a $1.6 million decrease to system NPC.

Q. What is your response to this adjustment?

A. The Company agrees that the generation from the Mountain Wind facilities has not been as originally expected. However, the Company does not agree with ICNU' s adjustment because it was based on a partial year of historical data and news clippings. In the current update, the Company updated the wind profile based on the latest information received from Mountain Wind. The impact of this update is a decrease in total Company NPC of approximately $1.8 million from the Company's Initial Filing.

ICNU Adjustment G.3 (SCL Stateline Contract Reserve)

Q. Please explain ICNU's proposed adjustment to SCL Stateline Reserves.

A. ICNU claims that the Company did not correctly model the SCL Stateline contract, and states that the contract requires SCL to provide PacifiCorp with a certain amount of operating reserves based on the capacity of the Stateline project, but that the Company did not model any of the reserve capacity. ICNU's adjustment would reduce system NPC by $1.6 million.

Q. Does the Company agree with ICNU's proposed adjustment?

A. Yes, in part. The Company agrees that [redacted] megawatts of reserve capacity should be modeled in GRID, because the SCL contract requires SCL to provide PacifiCorp with operating reserves equal to [redacted] percent of the contracted integration amounts based on the portion of the Stateline project that the Company manages for SCL per contract terms. The Company does not, however, agree with ICNU's correction increasing reserve capacity t[redacted]_ megawatts.

Q. Why does ICNU propose increasing the reserve capacity?

A. ICNU claims that the contract recently expanded to 209.2 megawatts, so it assumes that the amount of reserve capacity has increased to [redacted] megawatts.

Q. Is this a correct interpretation of the contract between the Company and SCL?

A. No. ICNU has misinterpreted the contract. There have not been any changes to the contract, neither the contract capacity nor the reserve capability provided by the contract. For this reason, the Commission should reject ICNU' s proposal to increase the amount of reserve capacity above the amount SCL is providing under the terms of its contract with the Company. As previously discussed in the corrections section, the Company has incorporated the modeling of the SCL contract reserve capacity in GRID. This adjustment decreases total Company NPC by approximately $1.2 million from the Company' s Initial Filing.

<u>Company Responses to Contested Adjustments</u>

Hydro Normalization

Q. What is the purpose of this section of testimony?

A. I respond to CUB' s, Staff' s, and ICNU' s proposed adjustments to hydro normalization.

Q. How is your testimony organized?

A. I first discuss the parties' adjustments related to the overall level of hydro production. I then turn to the parties' discussions of the Company' s hydro normalization methodology.

Overall Level of Hydro Production

Q. What has CUB proposed with respect to the overall level of hydro generation in the case?

A. CUB argues that a Company' s updated hydro forecast in March 2009 shows that its hydro generation is expected to increase by approximately 320,000 megawatt hours from 2009 to 2010. Based on the 2010 average prices of the long-term firm purchased power contracts in the Company's Initial Filing, $58.29 per megawatt hour, CUB calculated that the value of the increased hydro generation is $18.6 million on a total Company basis. As the result, CUB proposes that the Company's NPC should be reduced by that amount.

Q. Is CUB correct that the level of hydro generation in this case should be adjusted higher based on the figures cited by CUB?

A. No. The source information that CUB relies upon for the adjustment is a Company's response to Staff, CUB Exhibit 102. The Company expressly stated in its response that it did not rely on the information contained in that response in the current docket. Staff/103, Brown/2. CUB Exhibit 102 is a worksheet created by the Company's engineering department to plan for maintenance of hydro facilities.

Q. Why is the engineering worksheet not appropriate to use to calculate NPC in this case?

A. The engineering worksheet is not normalized. Instead, it uses 30 years of actual historical hydro data, adjusted for actual or expected maintenance overhauls. The worksheet also contains actual data for 2009 that show a decrease from historical generation. The worksheet contains actual hydro generation results for January and February of 2009, which total about 284,000 megawatt hours below the 30-year average. The worksheet also includes a major capital maintenance outage that reduces generation for 2009 by an estimated 60,000 megawatt hours. These two reductions account for a decrease in 2009 that is larger than the increase that CUB has calculated in hydro generation from 2009 to 2010. CUB' s use of this worksheet to claim that the Company is forecasting an increase in hydro generation between 2009 and 2010 is incorrect and should be rejected.

Moreover, Exhibit PPL/103, Duvall/10 shows that the normalized forecast hydro generation included in this case for 2010, 3,932,604 megawatt hours, already exceeds the " increased" level cited by CUB[redacted] megawatt hours. As a result, using the hydro calculation that CUB references would actually reduce hydro generation in the case and increase NPC.

Q. Does CUB propose that the Company use a model other than Vista to calculate hydro?

A. No. Despite relying on the non-normalized data in the engineering report to advocate an increase in hydro, CUB stated in response to PacifiCorp DR 1.1 (see Exhibit PPL/108, Duvall/1) that CUB is not proposing that PacifiCorp stop using Vista to forecast hydro generation.

Q. Does Staff also raise the issue related to the Company' s overall level of hydro generation in this case?

A. Yes. Similar to the issue raised by CUB, Staff argues that the Company' s hydro generation in 2010 should not be reduced from the level in its previous TAM proceeding, claiming that the Company is making inappropriate short-term adjustments to its hydro forecast.

Q. What adjustment does the Staff propose?

A. Based on a comparison with the Company' s indicative NPC in the previous TAM filing, Staff calculated the changes in generation of selected hydro resources and proposed an adjustment to reduce NPC by $12.7 million on a total Company basis. Staff points to the differences in the Company's modeling of three hydro facilities: Toketee, the Bear River system[1], and JC Boyle. In essence, Staff is replacing single-year median hydro data for selected projects with data from the three exceedence hydro data used in UE 199.

Q. What is your comment on such adjustment?

A. Staff's adjustment is not well founded. There are a number of legitimate reasons why hydro generation levels at particular facilities would differ from those in UE 199, including the change to the single-year median hydro method, various operating requirements at the hydro facilities, and updates to the historical data, including streamflow data, varying reservoir levels and outages that are used to produce the normalized hydro generation for a test period. It is reasonable to expect differences in normalized hydro generation levels in different test periods of different filings.

Q. What issue does Staff raise about Company's forecast hydro generation at the Bear River system?

A. Staff argues that the Company should not have reduced hydro generation from the Bear River system based on drought conditions on Bear River. Staff does not explicitly state its Bear River adjustment in the testimony, but Staff/102, Brown /1 shows that the adjustment is $8.0 million, total Company.

[1] In Staff/100, Bear River is mistakenly referred to as either Bear Creek or Bear River hydro complex.

Q. What is your response to Staff's adjustment?

A. The Company modeled the Bear River system to reflect current operating and multi-purpose water management constraints including: (1) The 1958 Bear River Compact approved by the United States Congress which prohibits the release of water from Bear Lake solely for power generation below the irrigation reserve level of elevation 5,914.61 feet; (2) the 2000 "Operations Agreement for PacifiCorp's Bear River System," which requires that the Company operate Bear Lake primarily for irrigation and flood control. This agreement was required by the states of Idaho, Wyoming and Utah as a condition for approving the acquisition of PacifiCorp by MidAmerican Energy Holdings Company; and (3) recently, the Company began modeling the impact of the new operating constraints required by the 2003 license for FERC Project #20, including the Grace Plant on the Bear River system, which mandates increased bypass flows below Grace dam for ameliorating fisheries and aquatic issues and to provide recreation opportunities (for example, white water boating). Water released into the river channel below the dam bypasses the turbine and cannot be used for generation. Together, the bypass flow and white water boating releases reduce total generation available from the Bear River by an estimated 19,000 megawatt hours.

Q. Please provide background on how the Company modeled Bear River generation in this case.

A. The dams on the Bear River have three potential sources of water for generation: natural inflow, water withdrawn from Bear Lake to supply downstream irrigators, and water withdrawn from Bear Lake for flood control purposes. The Company's operating agreements for the Bear River system referred to above prohibit the Company from withdrawing water from Bear Lake for generation and flood control purposes unless the lake elevation exceeds a certain level. For the past ten years, and for the foreseeable future assuming median streamflow into Bear Lake, this operational constraint has and will prevent the Company from operating the Bear River system with flood control releases. The lake elevation is currently projected to drop to about 5,910 feet this fall, which is 11 feet below the 5,921 feet elevation level that allows the Company to release flood control storage.

The Company previously modeled the Bear River system using historical normalized hydro generation for all three operational modes that included water supply from natural run-off, irrigation deliveries, and flood control releases, without considering the operational constraints around flood control operations. After a careful review, the Company concluded that the flood control mode of operation has now effectively become unavailable, and the Company has begun accounting for this operational constraint in its rate filings and business planning by excluding the generation using the flood control water in its normalized hydro generation.

Q. How do you respond to Staff and intervenor statements that normalized ratemaking should not reflect recent events?

A. As noted above, it has been more than ten years since the Bear River system operated in flood control mode. Normalized ratemaking should reflect an operating constraint such as this imposed by contract or a government entity. The

Company' s adjustment is based on a known and measurable change to the operating conditions and water management obligations of the Bear River system and as such is properly included in the calculation of NPC.

Q. Do you have any other concerns with Staff' s proposed hydro normalization adjustments?

A. Yes. Staff' s adjustment is based on the erroneous assumption that any " additional" generation between what is in the Company' s Initial Filing and what was in the Company indicative filing in the last year' s TAM will be sold to the COB or Four Corners market during heavy load hours. Staff argues that this dollar amount is an approximation of the potential cost impact of Staff' s proposed hydro adjustment. The Company recommends that any valuation of changes in hydro conditions be modeled in GRID to more accurately compute such value.

Q. What is the problem with Staff' s proposed adjustment value?

A. Staff has presented no evidence that the level of hydro generation in 2010 should be expected to be the same as it was in 2009. Staff makes arguments about a few specific facilities, but makes no attempt to show that, even if the Commission accepts Staff' s arguments with respect to those facilities, the level of hydro generation should be what Staff argues it to be. Staff has presented no justification for the market prices used to determine the adjustments, and when responding to the Company data request regarding the basis for using the market prices, Staff simply repeated what prices were used. Staff has presented no basis for finding the adjustment to be reasonable.

Hydro Normalization Methodology

Q. What has CUB stated with respect to the Company's hydro normalization methodology?

A. CUB raises concerns with Company's use of the single-year median hydro method to forecast hydro generation. However, CUB states that if the Commission accepts the use of a single-year median hydro input for normalizing hydro generation, then the Commission should order the Company to retain this new methodology until the next general rate case. The Company supports CUB's recommendation on this issue.

Q. Does Staff object to the Company's use of the single-year median hydro method to forecast hydro production?

A. No. Staff has not explicitly objected to the Company's use of the single-year median hydro method.

ICNU Adjustment A.1 (Eliminate Market Caps)

Q. What does ICNU propose with respect to market caps for the California Oregon Border, Palo Verde, Four Corners, and Mid Columbia wholesale market hubs?

A. ICNU proposes eliminating the midnight to 5:00 A.M. market caps in these four markets, and claims that the GRID model no longer needs to constrain these markets because there are willing wholesale buyers in these markets during these hours. This adjustment results in an $18.2 million decrease to system NPC.

Q. What is the purpose of market caps?

A. The market caps limit the sizes of wholesale sales markets during graveyard hours to reflect the fact that the wholesale market is not liquid during these hours. Without market caps, GRID would allow the Company's coal units to produce more power than can be absorbed in these markets during graveyard hours and would therefore overstate coal generation.

Q. Do you agree with ICNU that these market caps are no longer necessary?

A. No. ICNU's proposal to eliminate market caps would result in GRID modeling wholesale sales during graveyard hours in amounts that overstates actual coal generation.

Q. How did you conduct this analysis?

A. In the past, the Company has used the four-year historical generation to verify whether coal generation included in GRID is reasonable. Therefore, I compared the four-year actual historical generation to the generation produced by the GRID model in the Company's NPC study in its Initial Filing. I found that the level of coal generation modeled in GRID exceeded the actual four-year historical generation by 457,804 megawatt hours. The historical four-year period is the same as that was used as the basis to determine the availability of the thermal units in this proceeding. If the GRID coal generation were reduced to the historical levels, the Company would need to increase its request for base NPC by approximately $18 million, assuming a margin on coal generation of $40 per megawatt hour.

Q. Did the Company review the level of coal generation assumed in ICNU's NPC recommendation?

A. Yes. ICNU's final recommendation results in coal generation that exceeds the four-year actual historical generation ending June 2008 by 1,364,687 megawatt hours, even when ICNU has not completed its daily screens. The use of market caps is one way to keep GRID from optimizing to unreasonable levels, such as those produced by ICNU's NPC recommendation.

Q. What is your recommendation regarding market caps?

A. I recommend that the Commission reject ICNU's proposed adjustment because it will result in unreasonably high levels of coal generation and thereby understate system NPC.

ICNU Adjustment B.1 (Correct Improper Screens)

Q. Please explain ICNU's proposal to change the screens in GRID.

A. ICNU contends that the GRID model's commitment logic is imperfect because, at certain times, it dispatches three of the Company's gas plants—Gadsby, Currant Creek, and Lake Side—in a manner that fails to optimize the system. Specifically, ICNU complains that GRID dispatches the gas plants at times it does not make sense to do so, fails to dispatch the gas plants when they should be allowed to run, and the Company does no rigorous analysis of the days or hours when specific units should be prevented from running.

Q. What specific adjustments does ICNU propose?

A. ICNU proposes applying daily screens to gas-fired resources. This adjustment would result in a $2.8 million decrease to system NPC based on ICNU's incomplete studies.

Q. Do you agree with the basis for ICNU's adjustment?

A. No. Part of ICNU's argument to use daily screens is that each day, system operators are faced with new information about system and market conditions and monthly screens can not accommodate these daily variations. What ICNU fails to point out is that GRID is not affected by changes in forward price curves, loads and resources each day. These variables are fixed in GRID and do not change on a daily basis. The use of daily screens is unwarranted absent inclusion of including the daily volatility of system and market conditions in GRID.

Q. How did the Company decide which screens to apply in this case?

A. The Company used the monthly screens proposed by ICNU in UE 199 and expanded these to cover the Chehalis plant and the Gadsby units. ICNU has not explained what has changed since UE 199 to make daily screens necessary.

Q. If the Commission decides that daily screens are appropriate, should the Commission apply ICNU' s calculation of the adjustment?

A. No. ICNU' s calculation of the adjustment is incomplete and unverified. While claiming the daily screen method is logical and simple, ICNU' s discussion on the screens was partially based on data that the Company provided as the support to the Company' s screens, and the adjustment that ICNU made lacks the full set of necessary runs, a description about how GRID and the manual daily screens are the same or different in logic, and identification of what other sections of the GRID logic may or may not be replaced by the daily screens.

Q. Have you identified problems in ICNU' s daily screens?

A. Yes. Initial review of the methodology indicates that ICNU' s screens contain at least the following errors: ignores the minimum up time of the units; does not define appropriate screens during all 24 hours in a day to make the decision; fails to correctly account for the startup costs; and does not correctly account for the last hour to show net operating benefits. Additionally, the decision to start or shut down the unit can be erroneous when the block of hours under consideration exhibit both benefits and costs of running the unit.

ICNU Adjustment B.3 (Start Up Fuel Energy Value)

Q. Please explain ICNU' s adjustment related to start-up energy.

A. ICNU proposes that the Company include the energy associated with starting up Currant Creek, Lake Side, and Chehalis in GRID because the costs of startups are included in GRID. This adjustment would decrease system NPC by $3.9 million.

Q. Do you agree that there is value to energy associated with starting up these facilities that should be reflected in the normalized NPC?

A. No, for a number of reasons. First, start up energy is generated within the hour. Since there is no mid-hour market for start up energy, ICNU' s approach of modeling the startup energy as free resources is incorrect because it assumes that such energy is firm energy and can replace purchases or make sales. Second, the Company primarily uses its hydro generation to follow ramping at the gas-fired facilities. Therefore, the Company does not save fuel by ramping down coal generation or transact in the market while the gas units are ramping up if it is ramping down with hydro generation. Third, GRID does not reflect any loss of energy associated with ramping down units while gas-fired units are ramping up. Therefore, there is no additional energy that needs to be valued in the NPC study. In essence, ICNU' s proposal amounts to a double counting of energy.

Q. Do you agree with ICNU that the Company' s view that start-up energy has no value is an " outlier" compared with standard industry practice?

A. No. How each utility manages the start ups of their gas plants depends on their unique situation. The Company' s methodology is reasonable for the operation of the Company' s fleet of resources.

Long Term Contract Modeling

ICNU Adjustment C.1 (Call Option Sales Contracts)

Q. What is ICNU' s proposed modeling adjustment to call option sales contracts?

A. The adjustment proposes to substitute actual data for normalized data for call option sales contracts that the Company has with the Sacramento Municipal Utility District (" SMUD"), Black Hills Power (" BHP"), Public Service of Colorado (" PSCO"), and the Utah Municipal Power Agency II (" UMPA II"). The GRID model assumes for normalized purposes that the counterparties will maximize the value of the contract and take the power at the most economical time. ICNU proposes to adjust this input to reflect actual historical contract operation. This adjustment would result in a $5.7 million reduction in total Company NPC.

Q. Do you have any general comments about this proposed adjustment?

A. Yes. In addition to technical problems, this adjustment embodies an approach of optimizing flexible resources when it lowers NPC and not optimizing flexible resources when it raises NPC. It is based on the assumption that the Company acts rationally and other companies act irrationally. ICNU' s proposal violates any reasonable principles of consistency and fairness. If NPC are to be set using an optimization model, then all resources and contracts that are subject to being optimized should be. For this reason alone, the Commission should reject this proposal.

Q. Please explain.

A. The proposed adjustment departs from modeling power costs on a normalized basis. If this type of modeling adjustment were adopted, then consistency and fairness require its application to all other flexible purchase or sale contracts that are modeled in a similar fashion to the SMUD, BHP, PSCO, and UMPA II contracts. For that matter, it should also be applied to flexible generating resources. Optimization of the Company's system operations decreases NPC on a net basis. ICNU has not proposed "deoptimization" across the board, which would increase NPC—and potentially undermine ICNU's arguments on GRID commitment logic. Nor has ICNU provided any justification for selective "deoptimization" of only call option sales contracts, rather than both purchase and sale contracts and flexible generating units. The argument to change the modeling of the SMUD, BHP, PSCO, and UMPA II contracts should therefore be rejected.

Q. How do you respond to ICNU's argument that flexible wholesale sales contracts should not be optimized because the Company has not modeled any of the loads, constraints, or forward price curves used by the counterparties?

A. This is a baseless argument. The data referenced, as well as the strategies that the counterparties employ, are proprietary and unavailable to the Company. The Company must work with the data to which it has access. Given that the

Company is only one of the many participants in the market, the only assumption about how the counterparties will exercise their rights to the contracted energy, including the flexibility in the contracts, is to assume that all the participants in the same market are rational. To argue that the counterparties have no knowledge of forward prices in any liquid market is illogical and it is unreasonable to assume that the counterparties will not use the market information and optimize their operations to lower their operating costs.

Q. Is Exhibit ICNU/104 reasonable?

A. No. Exhibit ICNU/104 depicts the average hourly delivery shapes of those contracts over multiple years without consideration of any seasonal patterns and any other factors that may impact how the contracts would operate.

Q. Are there other practical problems with ICNU' s proposal?

A. Yes. Actual delivery patterns can be misleading. Both for the Company and other utilities, forward price curves and system conditions will be different in the 2010 test period than they were in the past. If there is an option to model a contract in GRID, that should be preferred over using actual historic data. This is the case for SMUD, BHP, PSCO and UMPA II. Whether the Company or another party is in control of when to take the purchased energy is beside the point. The actual conditions under which the rights to the contracts are exercised, including " delivery location, transmission constraints, availability of the counterparties' own generation and many other factors" as stated in ICNU/100, Falkenberg/27, could be very different from what were assumed in the optimization model. As the result, when the model-optimized deliveries of energy do not match actual historical deliveries of energy, it does not suggest that the actual deliveries were not optimized against the same considerations as in the model.

Q. Are there technical problems with ICNU's proposal?

A. Yes. To analyze the SMUD sales contract, ICNU relied upon incomplete data. For example, the data for 2004 ended on August 15, the data for 2005 do not include September, the data for 2006 do not include September through November, except November 15; and the data for 2007 ended on September 20. This is a sample of the days inexplicably missing in ICNU's analysis.

Q. How is the SMUD contract structured?

A. In addition to the firm energy, SMUD also has the right to take provisional power under the terms of the contract. When both of these are taken together, the shape proposed by ICNU does not comport well with the historical take by SMUD under the contract. Exhibit PPL/109, Duvall/1, shows the monthly pattern of the total firm and provisional sales in a four-year period, and Exhibit PPL/109, Duvall/2 shows the comparison of the month shape as modeled in the Company's Initial Filing and ICNU's proposal against the actual 2007 delivery pattern. The Company's modeling result does not perfectly match the historical take due to changes in various factors over the years, but it is a reasonable reflection of the contract performance and reflects the fact that SMUD would take less energy during the season when market prices are relatively low and take more energy later in the year when market prices remain relative high. ICNU's proposal, on the other hand, suggests that SMUD would take more energy in Spring than in Fall.

Q. Can you give another example showing that ICNU' s modeling of the call option sales is incorrect?

A. Yes. Using ICNU' s method of graphing the data, Exhibit PPL/110, Duvall/1 shows the four-year average hourly energy delivery profiles between what ICNU modeled and what the historical data show for the PSCO sales contract. The delivery profiles are used because it would not be comparable to use the amount of energy delivered during the period due to decline in the contract capacity. The exhibit displays heavy load and light load hours because PSCO' s historical energy take is distinctively different during the two periods. From the exhibit, it is clear that ICNU modeled the energy take at the level barely below the capacity factor dictated by the contract in all hours and only slightly higher in seven heavy load hours. The terms of this contract allows PSCO to take energy at 75 percent capacity factor for the contract year, with a minimum of 60 percent on an hourly basis and between 72 and 78 percent on a monthly basis. ICNU has not provided any support regarding why PSCO' s energy take should never be at its contracted minimum or should only have limited variations during the year. Exhibit PPL/110, Duvall/2, shows the energy take profile in the Company' s Initial Filing and the same historical averages. Similar to the comparison of the SMUD contract, the Company' s modeling result does not precisely match the historical take due to changes in various factors over the years, but it reflects the fact that there are differences between heavy load hour and light load hour periods, and there is flexibility during all hours to meet the contract terms similar to the manner in which PSCO takes power under the contract. This demonstrates that the modeling of this contract in GRID is reasonable.

Q. Does ICNU's modeling of BHP and UMPA II contracts have the similar problem?

A. Yes. Both of these contracts provide the counterparties with flexibilities within certain limits which are reasonably accounted for by GRID.

Q. Do you have other comments on ICNU's methodology of modeling the call option sales contracts?

A. Yes. It is inappropriate for ICNU to use the Company's modeling of non-flexible contracts with GP Camas, Idaho Power, Biomass and small purchases to justify its adjustments to the call option sales contracts. None of these contracts provide the Company the kind of flexibilities that are provided for in the terms of the call option sales contracts. Based on the principal of known and measurable information, the only thing known to the Company is the history of those contracts. This is simply another argument for selectively using the historical data when it reduces NPC.

ICNU Adjustment C.2 (Biomass)

Q. Please explain ICNU's adjustment for the Biomass Project contract.

A. ICNU argues that the Company should include in NPC a non-generation agreement with the Biomass Project on the basis that the Company has entered into such an agreement from 2005 through 2009. Under the agreement, the Company paid the Biomass Project to shut down during low market price months. ICNU's adjustment would reduce system NPC by $0.6 million.

Q. Why does the Company object to modeling this contract?

A. The TAM Guidelines provide that the Company will identify and provide support for "known contracts it expects to be updated or added in the Rebuttal and Final updates." The Company interprets "known contracts" as those it expects to have entered into by the time of the Final Update. ICNU concedes that the Company will not have entered into the contract before the August or November update. Therefore, the contract is not a "known contract" under the TAM Guidelines and should not be modeled in rates. If the Commission were to adopt this adjustment, it will make the definition of "known contract" under the TAM guidelines nebulous at best. The Company believes that defining "known contracts" to be "executed contracts" was the intent of the TAM guidelines.

ICNU Adjustment C.3 (Morgan Stanley Call Options)

Q. Please explain ICNU's proposed adjustment to the Morgan Stanley call option purchase contracts.

A. ICNU proposes to remove the Morgan Stanley call option purchase contracts 272156 and 272157 during uneconomic days and eliminate the demand charges during months the contracts are not dispatched. The adjustment would result in a decrease to NPC in the amount of $2.6 million on a total Company basis.

Q. What is the basis for ICNU's adjustment?

A. ICNU claims that the Company proposed to make such an adjustment in UE 191 and that the proposal was adopted by the Commission.

Q. Please explain how this adjustment came about in UE 191.

A. In the proceeding in which the Commission adopted Portland General Electric's

("PGE") Power Cost Adjustment Mechanism ("PCAM"), the Commission imputed extrinsic value to two contracts that did not dispatch in PGE's model. In UE 191, PacifiCorp and ICNU argued about whether and how this precedent should be applied to PacifiCorp. PacifiCorp expressly rejected ICNU's view that the decision implied that unless a contract energy component provides enough benefits to cover the premium, extrinsic value should be imputed. PacifiCorp noted that this argument was illogical, because option contracts are purchased to provide reliability and capture value when market prices increase. When the Company buys an option contract, the Company looks for out-of-the-money contracts that have a lower premium as a means of providing reliability while keeping costs low, because the contracts are not expected to be dispatched all of the time. If the Company were to buy in-the-money option contracts, the premium and overall cost would be higher because of the expectation that they would be dispatched most of the time.

Q. How was this adjustment resolved in the Oregon TAM case?

A. Ultimately, the Company agreed to remove the costs of option contracts if and when removal of the contracts lowered NPC. The Company noted that several of the contracts that ICNU sought to disallow did not have this impact when the Company updated the GRID runs.

Q. How is ICNU's proposed adjustment in UE 191 different from ICNU's proposed adjustment in this case?

A. The UE 191 adjustment used monthly screens to remove the costs of option contracts when they were uneconomic. The Company has already incorporated this monthly screen method in GRID. ICNU is proposing to apply daily screens that, as I discussed above, are inappropriate. ICNU has not presented evidence explaining how daily screens are necessary given that it proposed monthly screens in UE 191.

Q. How do you respond to ICNU' s proposal that the Commission disallow the premiums for these call option contracts?

A. The Commission should reject this proposal. When the Company enters into a call option contract, it is purchasing assurance that it will have energy available when there is no other resource available to ensure reliability. These contracts are not expected to dispatch regularly. ICNU' s proposal is similar to arguing that the Company should only be able to recover insurance premiums when it receives proceeds under an insurance policy. That position would be nonsensical, but that is just what ICNU is arguing with respect to call option contracts.

Q. Did the Company agree to an adjustment based on removing some call option premiums in UE 191?

A. Yes. Although the Company agreed to an adjustment based on removing some call option contract premiums in UE 191, the Company did not agree, and the Commission did not find, that disallowing premiums for call option contracts that do not dispatch in certain months is good regulatory policy. In fact, disallowing such premiums will provide a disincentive for utilities to enter into such contracts, resulting in higher NPC than would be the case if utilities entered into prudent call option contracts.

Q. Have other states recently considered whether to disallow premiums for call option contracts that do not dispatch in the test year?

A. Yes. In the Company's 2007 Utah rate case, the Utah Commission rejected a proposed disallowance based on removing premiums of call option contracts that did not dispatch in a given month. In that case as in this one, the Company agreed to remove variable costs of option contracts if and when removal of the variable costs lowered NPC.

ICNU Adjustment C.4 (GP Camas)

Q. What does ICNU propose with respect to the Georgia Pacific Camas ("GP Camas") power purchase contract?

A. ICNU proposes to reduce the purchase power volumes under the GP Camas contract to actual 2008 volumes. This would result in a $0.8 million decrease to total Company NPC.

Q. What is the basis of ICNU's proposal?

A. ICNU argues that generation levels at GP Camas have been declining, so the Company should reduce the amount of GP Camas contract volumes to the actual calendar 2008 volume.

Q. Do you agree with his adjustment?

A. No. The volume of GP Camas purchase power in the Company's NPC study represents the most current information that was available at the time the NPC study was prepared. ICNU's proposed adjustment should be rejected since the proposal is a one-off adjustment based on new information (from discovery in a Company docket in the state of Washington) without more comprehensively updating NPC for off-setting cost increases. In addition, ICNU's adjustment is inconsistent with the TAM Guidelines, because it is an update that is not a contract update, a correction from the Initial Filing, or remedying an omission from the Initial Filing. ICNU again seeks to have the Commission ignore the TAM Guidelines for an update that would lower NPC, but would certainly object if the Company attempted to do the same for an update that would raise NPC.

Q. Are there technical problems with ICNU's proposal for GP Camas?

A. Yes. ICNU's estimate is based on a regression analysis forecast prepared by ICNU that shows the GP Camas facility's generation reduces to zero by the end of 2012. This is an unrealistic result for which ICNU provides no support.

Adjustment D.1 (Hydro Input Corrections)

Q. What other adjustment has ICNU proposed for the hydro modeling?

A. ICNU proposed to change the timing of the "Hydro Reserve Input Parameter" to match the regulating margin requirement. ICNU's adjustment reduces the system NPC by $0.6 million.

Q. How do you respond to this adjustment?

A. The hydro reserve input parameter is used in the GRID model to ensure that adequate hydro reserves are available to meet the morning ramp up in loads. This has been an input to GRID that has remained unchanged since the Company began using GRID. ICNU questions the accuracy and suggests one way to modify the application of the parameter that reduces NPC. Because the reserve input parameter is designed to address intra-hour load changes, it is incorrect to use hourly data in GRID to justify the changes to this parameter. The Company agrees that this input deserves further consideration, however, and proposes to study this parameter and present its findings in its 2011 TAM filing.

Transmission Modeling

ICNU Adjustment F.1 (Cal ISO Fees)

Q. Please describe ICNU's adjustment to the Cal ISO Fees.

A. ICNU recommends removal of the Cal ISO fees that are based on 2008 actual costs incurred by the Company. ICNU's recommendation is based on the view that these costs were a direct result of the Company's trading activities in the SP 15 market, while there are no transactions modeled in SP 15 in the Company's Initial Filing. ICNU further recommends that if transactions are added in SP 15 in subsequent updates, the Company should receive a credit against ICNU's proposed Cal ISO fee disallowance. This adjustment results in an $11.2 million decrease to NPC.

Q. How do you respond to this adjustment?

A. I do not agree with adjustment. Cal ISO fees are incurred for transactions in SP 15, NP 15, and when the Cal ISO is the counterparty. Eliminating these costs solely on the basis of a lack of transactions in SP 15 is not reasonable. The Company continues to do business with the Cal ISO and continues to incur Cal ISO fees. There is no reason to arbitrarily eliminate expenses that are required to be incurred when doing business with the Cal ISO.

Q. Would removal of the Cal ISO as a counterparty affect the operations of the Company's power system?

A. Yes. The Company enters into transactions with the Cal ISO in order to economically balance the system. In doing so, the Company incurs Cal ISO fees. Not allowing the Cal ISO fees is the same as making the assumption that the Company would not do business with the Cal ISO. To properly remove the Cal ISO from GRID would require additional assumptions that would limit the Company’ s ability to fully utilize the market. Rather than determine how to change GRID, the Company recommends that the Cal ISO fees remain in the model.

Q. Does the Company expect that it will continue to do business with the Cal ISO in 2010?

A. Yes. The Company expects to continue to do business with the Cal ISO in the future and incur Cal ISO fees. Costs such as wheeling costs are typically quantified for ratemaking purposes by using the most recent historic data absent any known and measurable changes. This is exactly how the Company has normalized Cal ISO costs in this proceeding.

ICNU Adjustment F.2 (Non-Firm Transmission)

Q. Does ICNU propose adjustments to the Company’ s transmission modeling?

A. Yes, ICNU proposes that non-firm transmission be modeled in GRID. This adjustment results in a decrease of $2.5 million to system NPC.

Q. Do you agree to the inclusion of non-firm transmission in GRID?

A. No. The amount of non-firm transmission, by its nature and definition, is both difficult to accurately predict and model, and modeling such transmission as fully available is contrary to normalization principles.

Q. Did the Utah Commission require the Company to include non-firm transmission in GRID as represented by Mr. Falkenberg?

A. Yes. The Company has contested this approach and continues to believe that it represents poor regulatory policy.

Q. If the Company uses non-firm resources on a daily basis, why shouldn't the resources be included in GRID?

A. First, this is simply another example of using actual data when it lowers NPC, while otherwise using normalizing assumptions. Second, the GRID model uses a simplified transmission topology. A portion of the non-firm transmission transactions that are acquired on a daily basis are already assumed to be available in GRID by virtue of using a simplified transmission topology. Finally, non-firm transmission is just that; non-firm. As such, use of non-firm transmission has reliability implications that are not addressed in GRID. ICNU's adjustment does not address these reliability implications.

ICNU Adjustment F.3 (STF Transmission Link Test Year Synchronization)

Q. What is ICNU's proposal related to the inclusion of short-term firm transmission in GRID?

A. ICNU proposes adjusting how the Company modeled short-term firm transmission by using four-year averages to determine both the capacity and the cost of short-term firm links. In contrast, the Company used capacity based on a four-year average, but costs based on the most recent single year of data. This adjustment would reduce total Company NPC by $8.2 million.

Q. Does ICNU indicate why it proposed using a four-year average for both capacity and cost?

A. Yes. ICNU's witness Mr. Falkenberg states that he has previously proposed using a single recent year of data for including short-term firm transmission capacity, but the Company objected to that approach in other proceedings. In response to the Company's objections, ICNU proposes using a four-year average in this proceeding, and believes the capacity and costs need to be "synchronized."

Q. What is the Company's response?

A. Use of a four-year average for wheeling expenses for short-term firm wheeling contracts is not reasonable. This would be inconsistent with how other wheeling expenses are included in NPC. In addition, many of these costs do not have associated capacity with which they need to be "synchronized." Such costs relate to ancillary services or transmission services that are effective in areas that do not have transmission constraints and therefore do not affect transmission capacity in GRID.

The Company uses four-year average availability of the short-term firm transmission that, by definition, vary from year-to-year, and uses the most recent year of expense to capture the most recent costs associated with acquiring transmission services from third-party transmission providers. This normalizing methodology is identical to using a four-year average availability for the generating resource, but most recent fuel costs for the expenses of the generation.

ICNU Adjustment F.4 (Other Transmission Adjustments)

Q. What is ICNU' s proposed pro forma adjustment error?

A. ICNU claims that the Company included a pro forma adjustment reflecting two new five-year contracts with APS more than once.

Q. Is ICNU' s adjustment correct?

A. No. The error was in the Company' s workpapers supporting the wheeling expenses, but not in the wheeling expenses included in the NPC study. That is, ICNU' s adjustment removes an amount that is not in the Company' s Initial Filing.

Q. Please explain ICNU' s transmission imbalance adjustment.

A. ICNU argues that NPC should reflect the net value of transmission imbalance charges and fees the Company pays to or receives from third parties. This adjustment would result in a $2 million decrease to system NPC.

Q. What are transmission imbalances?

A. Transmission imbalances refer to the deviation of scheduled generation and actual generation. Because the Company is the control area operator, it is responsible to balance the load and resources within the control area at any given time. The amount of energy actually generated by the third-party generators often does not match what they schedule. When this occurs, the Company is required to supply power to meet shortages or absorb surplus generation.

Q. Is this reasonable to include the transmission imbalances in the normalized NPC?

A. No. In normal operation, it is assumed that there would not be any transmission imbalances, which reflects the assumption that, on average, third-party generators will deliver power to the Company as scheduled. The normalized NPC should reflect this expected normal condition.

Q. If imbalance energy were included in the normalized NPC study, how would it be valued?

A. It would likely raise NPC. Imbalance energy, either received by or delivered from the Company is not known until after the hour it is completed. This puts the Company in the position of having to hold additional resources in reserve to manage the unknown imbalances within the hour.

Q. Please explain ICNU's prior period adjustment.

A. ICNU states that it made a "more complete" prior period adjustment to remove out of period adjustments. This adjustment reduces total Company NPC by $0.3 million.

Q. Why should the Commission reject this adjustment?

A. This is another adjustment that is aimed at reducing NPC. It is claimed to be "more complete," but is very limited. ICNU's adjustment is based on data that Mr. Falkenberg obtained in two of the Company's filings in the state of Wyoming. Both of those filings used different test periods, each of which was different from the base period used in this proceeding. It is not appropriate to use data from the Company's other cases that use different base periods. The Company believes that its proposal is reasonable and that ICNU's proposed adjustment does not improve the accuracy of the NPC study.

Other NPC Adjustments

ICNU Adjustment G.2 (Thermal Generator Performance Inputs)

Q. What has ICNU proposed with respect to the Gadsby Unit 1 minimum capacity?

A. ICNU states that GRID reflects a higher minimum capacity than is supported in the real-time assumptions provided with the filing and used in prior cases. ICNU concludes that the inputs are in error.

Q. Are the GRID inputs for the Gadsby Unit 1 in error?

A. No. Gadsby must generate at a higher level than would otherwise be expected for the unit to provide spinning reserves due to unit stability issues. The lower limit would only be applicable if Gadsby were not to provide spinning reserves, but provide generation only. In both the Company's and ICNU's modeling, it is clear that the Gadsby unit is used mainly for providing reserves and must therefore run at a higher minimum capacity.

Q. Please explain ICNU's proposed adjustment to the capacity of Cholla Unit 4.

A. ICNU claims that the Company recently upgraded the capacity of Cholla Unit 4 from [redacted] to [redacted] megawatts and that the upgrade should be reflected in GRID. ICNU states that the transmission constraints limit the Company's ability to deliver more than [redacted] megawatts, but that the derations to the unit due to forced outages render this limit moot for the most part. ICNU proposes to make an adjustment to reflect possible derations due to transmission limits. The impact of this adjustment would be approximately $0.6 million on a total Company basis.

Q. Do you agree with ICNU's adjustment?

A. No. First, the adjustment ignores the physical transmission constraints on delivery of power from Cholla. ICNU's expected value mathematics incorporating the modeling convention of derating for forced outages is flawed because it assumes that deliveries from Cholla can exceed the physical transmission available at the point of interconnection of Cholla with the transmission system. Second, Cholla's capacity in the Company's NPC study represents the then-most current information available at the time the NPC study was prepared. Based on the TAM Guidelines, there is no basis for the Company to update the Cholla facility in its Rebuttal or Final Update, because it is not a contract update, or a correction or omission. ICNU's proposed adjustment should be rejected since the proposal is a one-off adjustment based on new information without incorporating any other more current information. In addition, ICNU has increased wheeling capacity without increasing wheeling expenses. Third, the deration to the units for forced outages is to capture the lost generation due to such outages. By arbitrarily increasing the availability of the units, ICNU understates the impact of forced outages and understates NPC.

Staff's Wind Integration Charge Recommendation and ICNU Adjustment G.3 (Long Hollow)

Q. What has Staff proposed with respect to the Long Hollow wind contract?

A. Staff proposes that the Company commit to modifying its Open Access Transmission Tariff ("OATT" or "Tariff") to include charges associated with providing wind integration services to non-owned wind facilities. Staff argues that the only benefit the Long Hollow agreement provides to PacifiCorp customers is the revenue PacifiCorp realizes for providing transmission service and operating reserves, but that the Company is not receiving revenue for wind integration services.

Q. Why doesn't the Company charge for wind integration resources related to the Long Hollow wind facility?

A. Staff is correct that the Company does not charge generators for the cost of wind integration, because such charges are not provided for under the Company's OATT. Before charging wholesale transmission customers for this type service, PacifiCorp would be required to make a rate application to FERC proposing a wind integration charge and FERC approval would be required. PacifiCorp is not aware of any other transmission provider that has requested or received approval for this type of charge at FERC.

Q. Does PacifiCorp have plans to submit a wind integration tariff to FERC for approval?

A. Not at this time. On May 13, 2009, FERC announced that it has commissioned a new study to assess reliable integration of wind energy into the transmission system. PacifiCorp will monitor and participate in this study as appropriate. Depending on the results of the study, PacifiCorp may include a wind integration tariff in its next FERC rate case, which is scheduled to be filed on or before June 2011.

Q. Does the Company agree that it should be required to request a tariff modification to include charges associated with providing wind integration services to non-owned wind facilities from FERC?

A. No. Staff' s proposal that PacifiCorp seek to modify its tariff to allow it to impose a wind integration charge on *only* non-owned wind facilities would likely violate the federal statutory mandate that PacifiCorp treat all transmission customers, affiliated and non-affiliated, on a not unduly discriminatory basis. In addition, it is not clear whether, under the same statutory mandate, FERC would permit a transmission provider to impose a charge on one type of generator (wind) that it does not impose on all other types.

Q. Has ICNU proposed an adjustment based on wind integration costs related to Long Hollow?

A. Yes. For the same reasons as Staff, ICNU seeks disallowance of $0.4 million total Company expenses related to providing wind integration services to the Long Hollow wind resource. The Commission should reject this proposed adjustment for the reasons discussed above.

In addition, the first 125 megawatt of output for the Long Hollow wind resources are designated as a resource by transmission customer Utah Associated Municipal Power Systems (" UAMPS"). The UAMPS transmission agreement predates FERC' s Open Access policies and PacifiCorp' s OATT. The UAMPS transmission agreement does not permit imposition of a wind integration charge. Any modification to the agreement would require a special rate filing at FERC before a wind integration charge for the Long Hollow resource could be assessed to UAMPS.

Q. Are the costs associated with wind integration a prudent expense?

A. Yes, as a balancing area authority, PacifiCorp must operate its balancing area by matching system resources to actual load fluctuations on a second-to-second basis through automatic generation control. Maintaining system balance is one of the key functions of a balancing area authority and is required to maintain system reliability including maintaining system frequency. Load fluctuations, outages, and generation output fluctuations all contribute to the need for balancing resources. The addition of renewable resources such as wind have the tendency to increase the need for balancing resources.

Staff Adjustment: Other Revenue

Q. Please explain Staff's recommendation with respect to "other revenue."

A. Staff argues that in years in which a stand-alone TAM is filed rather than in conjunction with a general rate case, if revenue associated with new resources is accounted for as "other revenue," the revenue is unrecognized in rates. Staff provides an example for which it states that if the Company had not filed a general rate case concurrently with this proceeding, then transmission revenue associated with the Pleasant Valley wind farm would not have been recognized in rates, but the costs of providing transmission services would be included in rates through the TAM. Staff argues that this asymmetry must be corrected in stand-alone TAM proceedings.

Q. What is your response to Staff's proposal?

A. Staff recently agreed in the TAM Guidelines to explicitly include the steam revenues associated with Little Mountain steam sales in stand-alone TAM filings. No other revenue items were included in the TAM Guidelines. This proposed adjustment is an attempt by Staff to expand that agreement and the scope of the TAM unilaterally and therefore the Commission should reject Staff's proposal. Moreover, Staff's proposal is inconsistent with Staff's other positions in this docket and in UE 210. Most revenue associated with resources, or "Other Revenue," is included in base rates, not in TAM rates. Staff's proposal to include Other Revenue in TAM rates, even though Other Revenue is included in base rates, is inconsistent with Staff's recommendation to exclude start-up O&M from the TAM filing on the basis that such costs are in base rates, not TAM rates. Consistency requires that the Commission exclude Other Revenue from stand-alone TAM rates other than the steam revenues associated with Little Mountain steam sales which parties agreed to include in stand-alone TAM filings. In addition, Staff's proposed treatment of Other Revenue is inconsistent with Staff's recommendation in UE 210 to include the dispatch benefit of new resources in NPC, even if fixed costs, or "other costs," are excluded from rates (Staff/1300, Brown 2-3). Staff cannot credibly argue that the Commission should exclude other costs from TAM rates while including Other Revenue.

UM 1355 Issues

Q. Please explain how you addressed issues being litigated in Docket UM 1355 in this proceeding.

A. I have made certain assumptions on these issues which are subject to change based upon the outcome of Docket UM 1355.

ICNU Adjustment H.1 (Planned Outage Schedule)

Q. How have you modeled planned outages?

A. The Company continues to use a four-year average for modeling planned outages without any change from its Initial NPC study.

Q. Please describe the adjustments to planned plant outages proposed by ICNU.

A. ICNU agrees with the use of a four-year average, but contests the schedule the Company used for its planned outages and substitutes its own schedule. Different from ICNU' s lengthy discussion on how the Company' s planned outage schedules compare with the historical schedules and how reasonable the alternative schedule might be, its adjustment simply moves the planned outages of some units by a few days to eliminate slight overlaps of having two units at the same facility on planned outage at the same time, moves the planned outage at Colstrip from the fall to the spring, uses a later start date for the Hermiston outages, and moves the planned outage at Currant Creek from the fall to the spring. ICNU' s adjustment decreases NPC by $2.5 million on a total Company basis.

Q. Do you agree with the adjustment that ICNU is proposing?

A. No. ICNU' s shifting of planned outage schedules is arbitrary and unsupported by facts. For example, combined cycle combustion turbines such as Currant Creek require planned outages after a certain number of hours of operation. They can not be targeted for a particular time of the year in the way coal plants can be scheduled. ICNU moves the planned outage of Currant Creek from the fall to the spring to reduce NPC, which is a significant portion of ICNU' s adjustment, without demonstrating that it is unreasonable to forecast this maintenance in the fall. [redacted]

Q. Have you submitted testimony on this issue in UM 1355 that is relevant to the Commission's consideration of planned outages in this proceeding?

A. Yes. I request that the Commission take official notice of my testimony on planned outages filed in UM 1355: PPL/400, Duvall/7, l. 18-Duvall/12, l. 16; Exhibit PPL/402; Exhibit PPL/403; PPL/405, Duvall/20, l. 8-Duvall/21, l. 7.

ICNU Adjustment H.2 (Outage Rate Weekend/Weekday)

Q. Have you included a weekday/weekend split in outage rates?

A. Yes. The Company has incorporated this adjustment, which results in a $1.2 million decrease to NPC on a total Company basis after Company's corrections and updates.

ICNU Adjustment H.3 (Ramping)

Q. Have you made any changes to the ramping adjustment?

A. No. The Company has submitted testimony and evidence on ramping in UM 1355. I request that the Commission take official notice of my testimony on ramping filed in UM 1355: PPL/400, Duvall/17, l. 3-Duvall/20, l. 7.

Q. Please describe ICNU's ramping adjustment.

A. The Company has added a ramping adjustment to NPC to account for decreased availability when generating units are started-up. ICNU proposes to remove this adjustment as applied to the Jim Bridger plant, decreasing NPC by $0.6 million on a total company basis.

Q. Please explain why the Company included its ramping adjustment.

A. The logic in GRID assume that generation units can go from zero to full load instantaneously when restarted after being offline for various reasons. In reality, units cannot be at full load instantaneously when ramping up from being offline due to the physical capabilities of the units. Generation is lost while a unit ramps to the minimum level required for synchronizing with the power grid and when ramping up to full load. The Company' s ramping adjustment simply reduces thermal availability to reflect generation not available due to ramping. This lost generation is not captured in GRID in any other way.

Q. ICNU claims that the Company' s ramping adjustment to Jim Bridger is based solely on assumptions and that the Company has no data to support its adjustment. Is that the case?

A. No. ICNU misinterprets a data response by the Company. Because the Company does not own the entire Jim Bridger plant, and is not the operator of the plant, the data available to the Company is on only a total unit basis. Since the Company owns two-thirds of each unit at Jim Bridger, the Company computes the ramping adjustment using two-thirds of the total amount.

Q. ICNU claims that the Commission' s practice is not to include a ramping adjustment. How do you respond to this?

A. This has not been an adjustment that has been addressed by the Commission for PacifiCorp. ICNU' s claim has no merit.

ICNU Adjustment H.4 (Minimum Loading and Deration)

Q. Have you changed how you model minimum loading and deration in this update filing as compared to the Initial Filing?

A. No. My testimony in UM 1355 contains extensive analysis of this issue and demonstrates why ICNU's minimum loading and deration adjustments are incorrect. I request that the Commission take official notice of my testimony filed in UM 1355 on minimum loading and deration: PPL/400, Duvall/12, l. 17-Duvall/17, l. 2; Exhibit PPL/404; PPL/405, Duvall/16, l. 5-Duvall/20, l. 7.

ICNU Adjustment H.5 (Combined Cycle Plant Outage Rates)

Q. What is this adjustment?

A. ICNU's adjustment is to address the outage rates of new resources. This adjustment decreases NPC by $2.9 million on a total Company basis.

Q. How have you modeled outage rates of new resources in this update filing?

A. The Company used the manufacturer's model specific fleet availability average to set the forced outage rate for the first two years. After that, the Company phased in actual operating data over four years, using a weighted average of the actual operating data and the manufacturer's model specific fleet availability average, excluding the first year of actual operating data. The impact of applying this methodology is a reduction of $1.7 million on a total Company basis after Company's corrections and updates.

ICNU Adjustment H.6 (Other Outage Rate Adjustments)

Q. What have you modeled with respect to the forced outage rates of peaking plants?

A. The Company applied EFOR-d to all Gadsby units and to any new peaker plants in this update filing.

Q. How does this affect NPC in this case?

A. This change to EFOR-d results in a $0.2 million decrease to NPC after Company' s corrections and updates.

Q. Have you made any adjustment for extreme outages/outliers in this proceeding?

A. Yes. In this filing, the Company has limited the forced outages to no more than 28 days. The impact of such change has been included in the impact due to adjustment of splitting outages to weekend and weekday (ICNU Adjustment H.2).

Q. What comment do you have regarding ICNU' s adjustment to long outages?

A. The initial review of the adjustment indicates that ICNU' s calculation of the adjusted EOR was in error, which is also confirmed by ICNU' s response to PacifiCorp' s DR 1.6 (see Exhibit PPL/108, Duvall/2), although ICNU claims that its calculation is identical to the Company' s formula. The Company believes that this claim is not correct.

Other UM 1355 Issues

Q. Are there any other issues that will be resolved in UM 1355 that cause a change in NPC in this proceeding?

A. Yes. The Company removed forced outages from its normalized hydro generation in this update filing. However, the Company may revisit the issue in future TAM proceedings. The impact of this adjustment on NPC is $0.4 million on a total Company basis after Company' s corrections and updates.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Docket No. UE-207
Exhibit PPL/105
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

Summary of Changes to Net Power Costs

August 2009

Oregon TAM - UE 207
Total Company Net Power Costs
Updates and Rebuttal
August 2009

Oregon TAM 2010 (March Filing)	NPC ($) =	**1,100,545,210**
	$/MWh =	**$ 18.76**

Oregon TAM 2010 (August Filing):

		Impact ($)	NPC ($)
Update, one-off			
1	New LADWP Purchase Contracts	(724,224)	
2	Black Hills Sales Contract Energy and Capacity Prices	(319,010)	
3	Tri-State Purchase Contract Energy and Capacity Prices	296,219	
4	New Chevron Wind QF	540,349	
5	Oregon Wind Farms QF (two additional wind resources)	1,113,404	
6	June-09 OFPC, STF Electric and Gas Transactions	5,604,120	
7	Extended Termination Date of Condit Dam	(2,992,086)	
8	Wind Profiles for Mountain Wind I and II QFs	(1,831,901)	
9	Idaho Power Company Wheeling Expenses	4,828,564	
10	New Stahlbush Island Farms QF	250,430	
11	New Lower Valley Energy QF	159,793	
12	BPA Wind Integration Charges	(3,337,620)	
13	Coal Contracts	4,022,579	
Correction, one-off			
1	Reserve Capability of SCL Stateline Contract	(1,205,396)	
2	Idaho Power Purchase Contract	(373,266)	
3	Hermiston Exchange Rate	(4,354,708)	
4	Currant Creek and Lake Side Planned Outages	(1,099,179)	
5	Overlapping of Planned Outages	(339,385)	
6	Maximum Regulating Margin	(3,018,228)	
7	Duct Firing Runs without the Main Unit	(113,668)	
8	Long Hollow in Non-owned Generation	162,060	
9	Chehalis Startup Costs for Commitment	1,087,872	
	System balancing impact of all adjustments	1,785,253	
	Total Adjustments from March Filing =	141,972	
	Oregon TAM 2010 NPC, prior to adopted adjustments		**1,100,687,182**
Adopted, cumulative after all corrections and updates			
1	Chehalis Modeling	(39,412)	
2	Gadsby EFOR-d	(246,281)	
3	Weekday/Weekend EOR	(1,205,085)	
4	Outage Rates of New Resources	(1,671,332)	
5	Exclude Hydro Forced Outages	(387,770)	
6	Screen of Gas Units	(825,434)	
7	Exclude Startup O&M	(912,000)	
	Total Adjustments from Updated =	(5,287,313)	
	Oregon TAM 2010 NPC, August Update		**1,095,399,869**

Docket No. UE-207
Exhibit PPL/106
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

Oregon Allocation of Net Power Costs

August 2009

Allocated NPC to Oregon for TAM

2010 TAM Filing - August Update

	ACCOUNT	FINAL UE-199 CY 2009	Original Filing CY2010	August Update CY2010		FINAL UE-199 CY 2009	FILED CY2010	FINAL UE-199 CY 2009	Original Filing CY2010	August Update CY2010	
Sales for Resale											
Existing Firm PPL	447	24,281,555	24,656,916	24,975,068	SG	26.411%	26.877%	6,413,106	6,627,011	6,712,520	
Existing Firm UPL	447	25,490,590	25,490,589	25,490,589	SG	26.411%	26.877%	6,732,429	6,851,076	6,851,076	
Post-Merger Firm	447	882,169,664	696,790,188	639,656,892	SG	26.411%	26.877%	232,993,623	187,275,491	171,919,842	
Non-Firm	447	-	-	-	SE	25.525%	25.002%	-	-	-	
Total Sales for Resale		931,941,809	746,937,693	690,122,550				246,139,158	200,753,578	185,483,438	
Purchased Power											
Existing Firm Demand PPL	555	62,711,383	57,671,363	59,132,864	SG	26.411%	26.877%	16,562,973	15,500,265	15,893,071	
Existing Firm Demand UPL	555	46,726,726	47,195,846	46,584,477	SG	26.411%	26.877%	12,341,196	12,684,773	12,520,456	
Existing Firm Energy	555	66,847,124	55,596,693	58,930,634	SE	25.525%	25.002%	17,062,586	13,900,229	14,733,777	
Post-merger Firm	555	707,106,149	376,422,870	351,557,140	SG	26.411%	26.877%	186,756,845	101,170,739	94,487,605	
Secondary Purchases	555	-	-		SE	25.525%	25.002%	-	-	-	
Seasonal Contracts	555	7,688,490	-	-	SSGC	24.488%	0.000%	1,882,756	-	-	
Other Generation Expense	555	5,247,531	11,022,399	7,682,475	SG	26.411%	26.877%	1,385,948	2,962,477	2,064,810	
Total Purchased Power		896,327,403	547,909,171	523,887,589				235,992,304	146,218,483	139,699,720	
Wheeling Expense											
Existing Firm PPL	565	31,031,711	43,189,893	43,189,893	SG	26.411%	26.877%	8,195,919	11,608,098	11,608,098	
Existing Firm UPL	565	172,448	168,268	168,268	SG	26.411%	26.877%	45,546	45,225	45,225	
Post-merger Firm	565	83,334,742	96,107,739	100,936,303	SG	26.411%	26.877%	22,009,897	25,830,766	27,128,533	
Non-Firm	565	184,789	282,748	274,921	SE	25.525%	25.002%	47,167	70,692	68,735	
Total Wheeling Expense		114,723,691	139,748,649	144,569,385				30,298,529	37,554,781	38,850,591	
Fuel Expense											
Fuel Consumed - Coal	501	568,676,213	604,154,098	610,654,307	SE	25.525%	25.002%	145,153,389	151,049,995	152,675,171	
Cholla / APS Exchange	501	57,517,646	54,964,906	55,207,439	SSECH	25.897%	25.405%	14,895,507	13,963,575	14,025,190	
Fuel Consumed - Gas	501	27,408,356	21,128,538	8,793,603	SE	25.525%	25.002%	6,995,924	5,282,536	2,198,568	
Natural Gas Consumed	547	374,811,293	458,583,217	426,442,274	SE	25.525%	25.002%	95,669,782	114,654,511	106,618,665	
Simple Cycle Combustion Turbines	547	23,655,228	17,499,425	12,469,820	SSECT	24.286%	23.563%	5,744,981	4,123,302	2,938,202	
Steam from Other Sources	503	3,541,671	3,494,899	3,498,000	SE	25.525%	25.002%	904,004	873,791	874,566	
Total Fuel Expense		1,055,610,407	1,159,825,082	1,117,065,444				269,363,588	289,947,711	279,330,362	
Net Power Cost		1,134,719,692	1,100,545,210	1,095,399,869				289,515,263	272,967,396	272,397,235	
Net Power Costs in Rates from UE-199		**1,043,323,002**						**266,835,529**			
			57,222,208	(5,145,341)					**6,131,867**	**5,561,706**	Increase Absent Load Change
						Oregon-allocated NPC Baseline in Rates from UE 199	$	266,835,529			
						2009 MWH (excluding Schedule 33)		14,026,969			
						$/MWH in Rates		19.02			
						2010 MWH (excluding Schedule 33)		13,267,901			
						2010 Recovery of NPC in Rates	**$**	**252,395,751**			
									20,571,645	**20,001,484**	Increase With Load Change
										(570,162)	Variance from Original Filing

CONFIDENTIAL
Docket No. UE-207
Exhibit PPL/107
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

Confidential Response to PacifiCorp Data Request

August 2009

THIS EXHIBIT IS CONFIDENTIAL AND PROVIDED UNDER SEPARATE COVER

Docket No. UE-207
Exhibit PPL/108
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

Non-Confidential Responses to PacifiCorp Data Request

August 2009

August 6, 2009

TO: **Katherine McDowell**
McDowell & Rackner PC
(Counsel for PacifiCorp)

FROM: **Gordon R. Feighner**
Utility Analyst, Citizens' Utility Board

CITIZENS' UTILITY BOARD
UE 207
CUB Response to Pacificorp Data Request Nos. 1.1-1.5.
July 28, 2009

Request 1.1:

See CUB/100, Jenks-Feighner/3, ll 14-15. Does CUB propose that the Company eliminate the use of Vista to forecast hydro production? If yes, what alternative model does CUB propose that the Company use?

Response:

CUB is not, at this time, proposing that PacifiCorp eliminate the use of Vista to create hydro generation forecasts.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UE 207

ICNU'S RESPONSE TO PACIFICORP'S DATA REQUEST NO. 1.6

Data Request No. 1.6:

Reference Mr. Falkenberg's workpaper titled, "Long Outages.xls" supporting Adjustment 40 that is part of Adjustment H.6 Other Outage Rate Adjustments. Please explain the formula used to calculate the revised EFOR.

Response to Data Request No. 1.6:

The formula used to compute the adjusted EFOR for Carbon 1 is shown on Cells M16, O16, U16 and U17 of the file Long Outages.xls provided with the workpapers. Similar formulae were used for Craig 1. The formula used is identical to the Company formula for computing EFOR in its workpapers. The logic used was to determine the change in overall outage rates for these units, then deduct that amount from the weekend and weekday outage rates. Mr. Falkenberg would not object to a more rigorous calculation that differentiated the formula between weekend and weekdays.

Docket No. UE-207
Exhibit PPL/109
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

SMUD Sales Contract Tables

August 2009

Exhibit PPL/109
Duvall/1

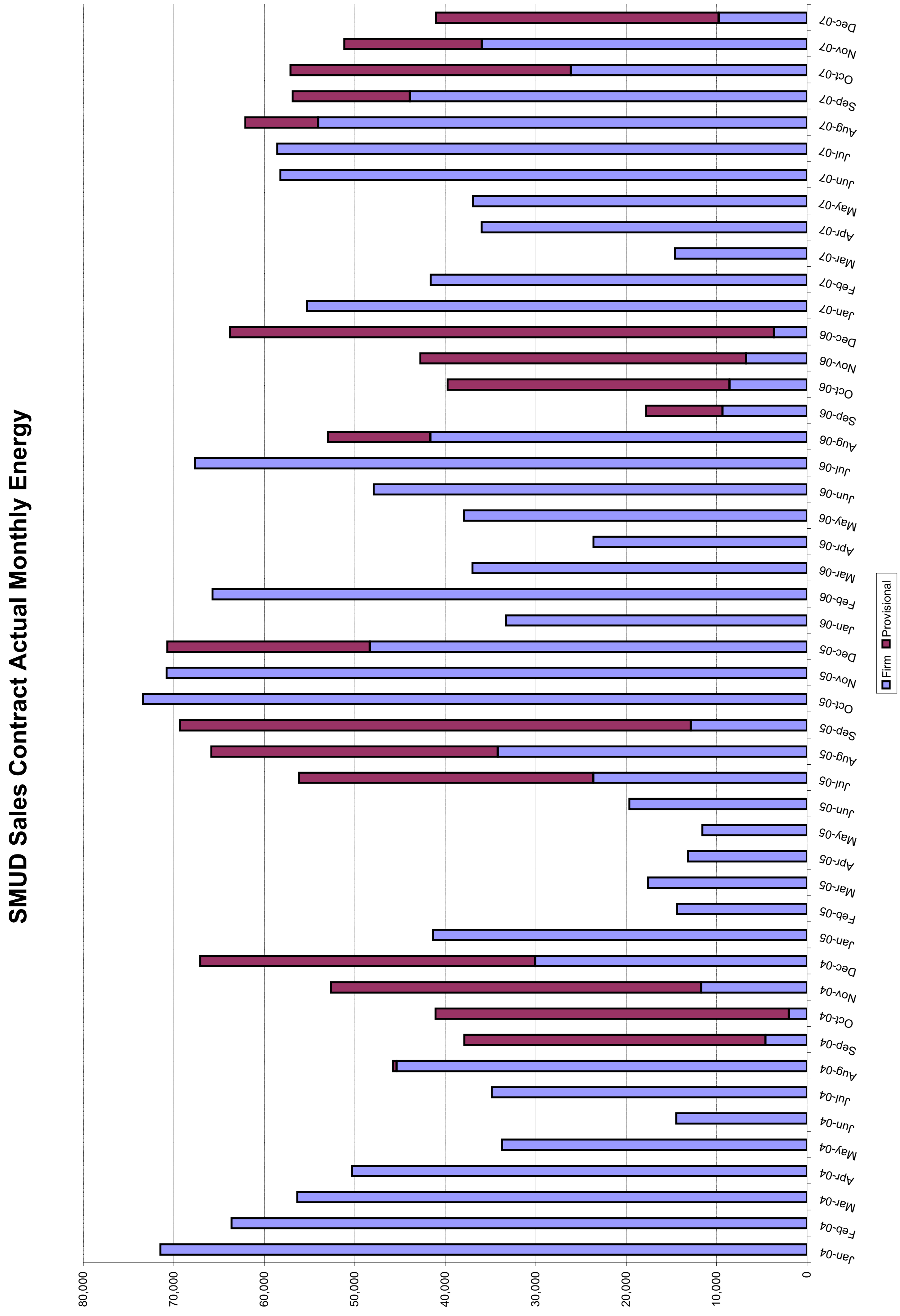
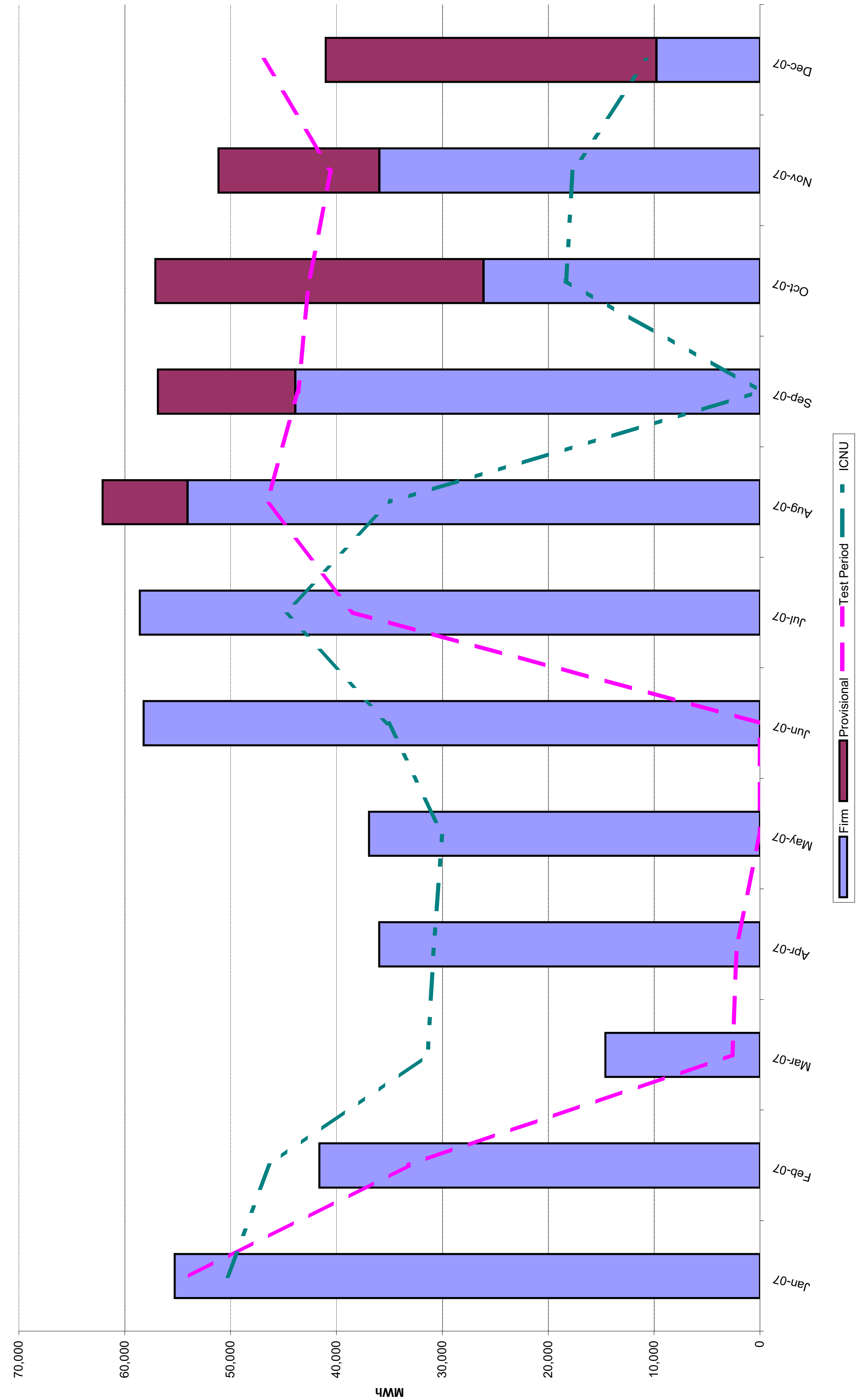


Exhibit PPL/109
Duvall/2

SMUD Sales Contract Monthly Energy
2007 actual and filed in test period



Docket No. UE-207
Exhibit PPL/110
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

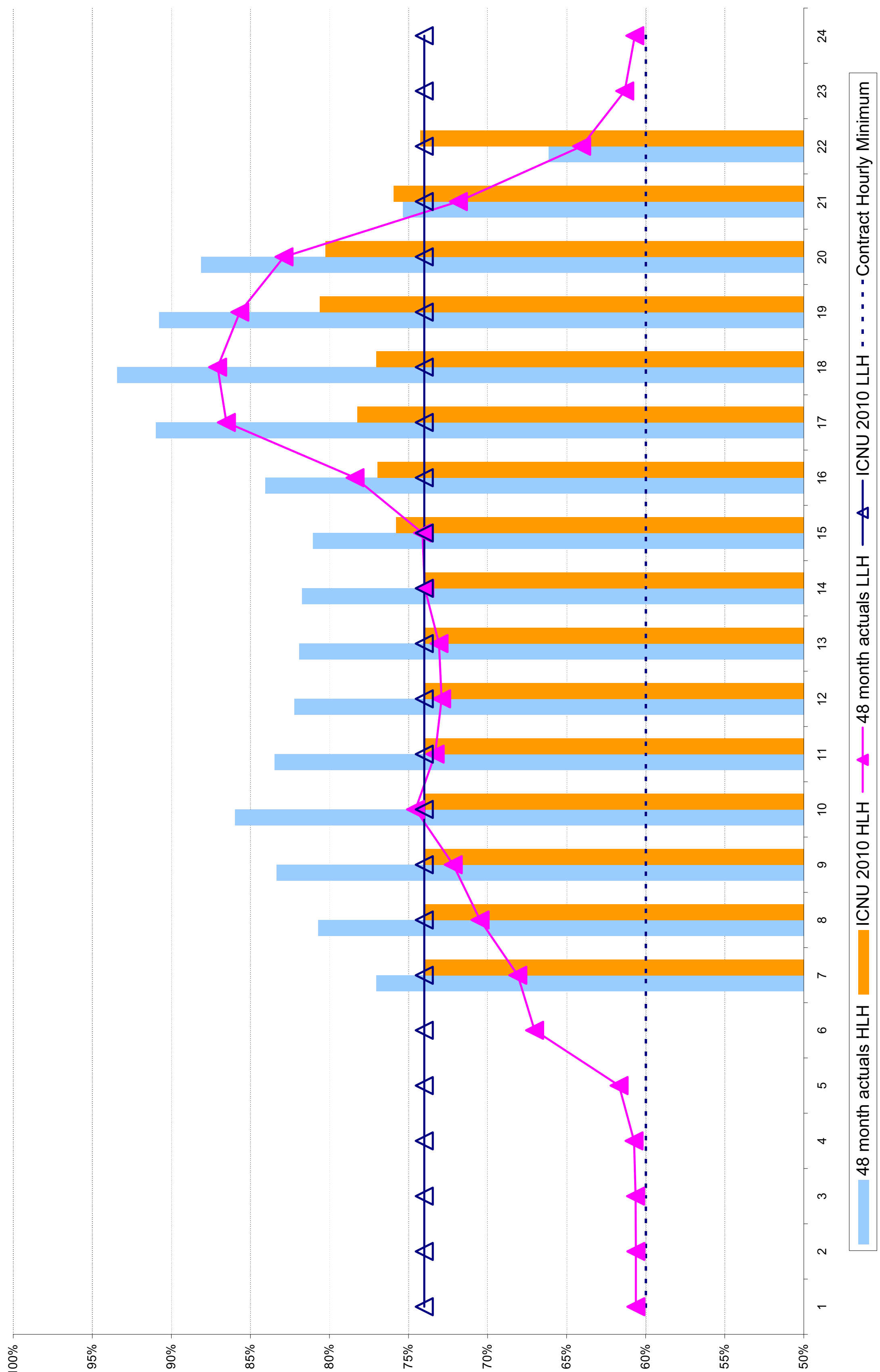
Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

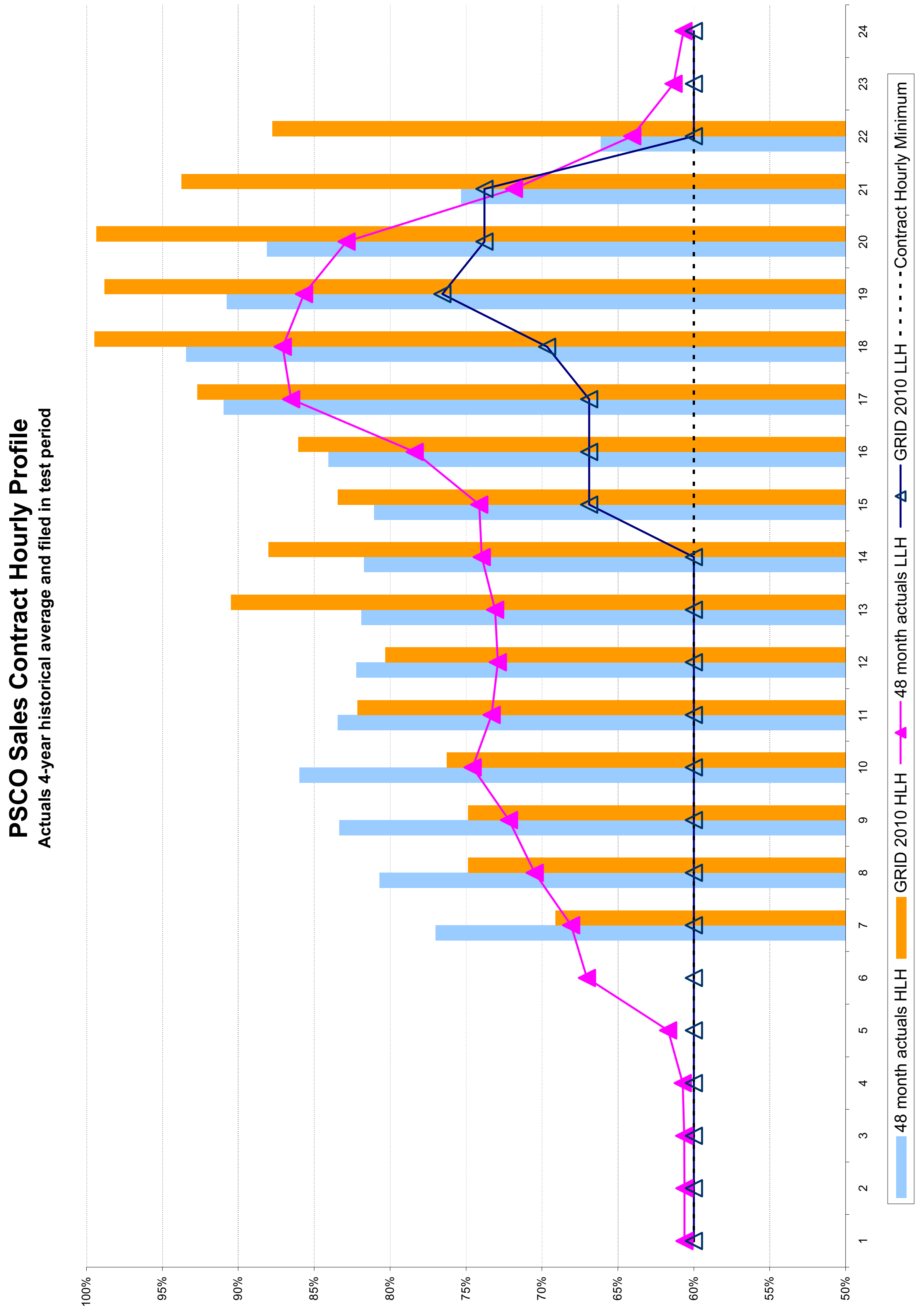
PSCO Sales Contract Tables

August 2009

PSCO Sales Contract Hourly Profile

Actuals 4-year historical average and modeled by ICNU




PSCO Sales Contract Hourly Profile
Actuals 4-year historical average and filed in test period
100%
95%
90%
85%
80%
75%
70%
65%
60%
55%
50%
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
48 month actuals HLH
GRID 2010 HLH
48 month actuals LLH
GRID 2010 LLH
Contract Hourly Minimum

Docket No. UE-207
Exhibit PPL/201
Witness: A. Robert Lasich

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of A. Robert Lasich

August 2009

Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power (the “ Company”).

A. My name is A. Robert Lasich. My business address is 1407 West North Temple, Suite 320, Salt Lake City, Utah, 84116. My position is President, PacifiCorp Energy.

Q. Have you previously filed testimony in this case?

A. Yes. I filed Direct Testimony in this case.

Q. What is the purpose of your testimony?

A. I explain that the Company’ s cost increases related to Emerging Issues Task Force (“ EITF”) 04-6, the accounting standard applicable to the Bridger mine, are necessary and prudent. I present the Company’ s proposal to minimize volatility in the Company’ s coal costs by establishing a regulatory asset balancing account. Lastly, I explain that the specific line item costs related to both the Bridger Coal Company and Deer Creek mine identified by Staff have not been shown to be imprudent.

Q. Please explain how the Company incurs stripping costs.

A. Depending on certain geological and other conditions, the Bridger mine extracts coal by utilizing various underground and surface mining techniques. Surface mining requires the removal of soil, rock or “ overburden” on seams of coal, which lie near the surface and cannot be safely or economically mined by subterranean operations. The Bridger mine utilizes “ draglines” in its surface mine to remove overburden. The costs of removing overburden and waste materials are referred to as “ stripping costs.”

Q. Please explain how EITF 04-6 impacts Bridger mine's 2010 costs.

A. Pursuant to FASB standard EITF 04-6, Bridger mine is required to include stripping costs in the cost of coal that is extracted in a given year, even if the stripping results in "uncovered" inventory available for extraction in subsequent years. The effect of this accounting requirement is that the cost of coal extracted in years when more coal has been uncovered than extracted, as a result of overburden stripping, is more expensive than coal extracted in years where more coal has been extracted than uncovered. Depending on certain variables, including mining practices, geology and production schedules, coal may or may not be extracted in the same year stripping costs have been incurred.

In 2010, the Company is expected to incur stripping costs for coal that will remain in the mine and be extracted in later years. This results in higher costs for the coal actually extracted in 2010. This will result in an increase in the cost of the surface mine operations, from approximately $39 per ton to $57 per ton, and an increase in the overall cost of Bridger coal from $30.63 per ton to $33.54 per ton. As noted in Staff's footnote 22, the 2009 weighted cost of Bridger coal was $30.57 per ton. Viewed in this manner, it is clear that the 2010 cost increase at the Bridger mine is largely related to EITF 04-6.

Q. Why is the impact of EITF 04-6 in this filing more pronounced than in previous years?

A. Bridger mine was first required to comply with EITF 04-6 in 2006. Due to our objective to focus mining operations to implement a least-cost mine plan, Bridger mine has decreased extraction of surface coal and increased underground mining as surface mine stripping ratios increase, thus increasing costs. As a result, there is a greater disparity in years where stripping costs are incurred and when coal has been extracted. In future years, the magnitude of the disparity will fluctuate depending on the amount of coal extracted.

The Company is required to comply with this accounting standard. While ICNU recommends that the Commission normalize (*i.e.* eliminate) the costs in the case resulting from this accounting change, ICNU provides no justification or basis for denying the Company recovery of these costs as unnecessary, unreasonable or imprudent.

Q. How does the Company propose to handle the impacts of EITF 04-6?

A. In August 2009, the Company plans to file accounting applications in all states seeking to establish a regulatory asset balancing account that would reduce the volatility of coal costs from the Bridger mine and return the Company to the accounting methods that were used prior to the adoption of EITF 04-6. Under this approach, coal costs in rates would be based on "uncovered" inventory (prior to EITF implementation) rather than the EITF "extracted" inventory method. The Company will seek to receive approval of the accounting orders in time to reflect the impact in rates by January 1, 2010. In the case of the Oregon TAM, the Company will seek an order in time to allow the final TAM update to reflect this accounting treatment and eliminate the artificial increase in coal costs caused by the accounting pronouncement and creates a timing mismatch of assigning stripping costs only to the extracted coal. Such an order would result in an effective price for 2010 Bridger coal supply that approximates 2009 levels.

Q. What will be the result of such an accounting order?

A. In general, the result of the accounting order I describe would be to undo the effect of EITF 04-6 and would allow the Company to employ the accounting method applicable to these costs in the absence of EITF 04-6. This treatment would reflect the accounting practices prior to the implementation of EITF 04-6 in 2006. Customers will benefit over the life of the mine through reduced volatility and reduced net power costs as compared to net power costs including the effect of EITF 04-6.

Q. Staff also identified line item costs, such as management wages and overtime, related to Bridger Coal Company and Deer Creek mine that Staff would recommend as adjustments during a general rate case. Staff did not make these adjustments in this case because Staff's lower of cost or market analysis resulted in greater adjustments. What is your response to Staff's testimony on this issue?

A. Staff has not presented any justification or basis for the Commission to find the identified costs to be imprudent. Even if the Commission rejects Staff's lower of cost or market adjustments to Bridger and Huntington costs, the Commission should reject any adjustment based on the line item costs identified by Staff because Staff has not presented empirical support for such an adjustment. For instance, Staff does not appear to take into account an increase in head count at the Bridger mine associated with increased underground mining, nor do they appear to understand the purpose and practice of management overtime at the Bridger mine.

Q. Does this conclude your testimony?

A. Yes.

REDACTED
Docket No. UE-207
Exhibit PPL/400
Witness: Bret C. Morgan

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Bret C. Morgan

[REDACTED]

August 2009

Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power (the “ Company”).

A. My name is Bret C. Morgan. My business address is 1407 West North Temple, Salt Lake City, Utah, 84116. My present position is Manager, Fuel Supply for PacifiCorp Energy, a division of PacifiCorp.

Qualifications

Q. Briefly describe your education and business experience.

A. I manage the group that develops and delivers the fueling plans and strategies for PacifiCorp Energy’ s thermal coal fired plants. I oversee the negotiation of the coal supply and transportation agreements which provide the fuel for the plants, approximately 25 million tons of coal at a cost of more than $600 million annually. I assumed my current position in 1997. I joined PacifiCorp in 1983 and progressed through a variety of positions that include manager, fuel contract administration; senior fuels analyst; property tax specialist; and property accounting cost analyst. I have a Bachelor’ s degree in Accounting from the University of Utah. I serve on the Board of the Trapper mine. I have participated in the business leadership program sponsored by the Wharton School of Business.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. I respond to the testimony of Staff witness Mr. Michael Dougherty proposing adjustments related to the Company’ s coal supply costs. Company witness Mr. A. Robert Lasich presents testimony explaining the impact of EITF 04-6 on the Company’ s coal costs and the Company’ s proposal to minimize volatility in the

Company’s coal costs by establishing a regulatory asset balancing account.

Q. Please summarize your testimony.

A. My testimony demonstrates that the Company’s coal supply costs are reasonable and that the Commission should reject Staff’s and ICNU’s adjustments asserting otherwise. Specifically, I address the following issues:

- I explain that the TAM update for the actual cost of market-based coal supply to the Dave Johnston plant moots the Staff’s proposed adjustment substituting an escalated spot market price for the Company’s forecast price.
- I demonstrate that the costs of coal from the Deer Creek mine are below prices available from non-affiliated suppliers for comparable coal supplies, refuting Staff’s adjustment related to coal supply at the Huntington plant under a “lower of cost or market” affiliated interest standard.
- I demonstrate that the costs of coal from the Bridger Coal Company (“Bridger mine”) are below prices available from non-affiliated suppliers for comparable coal supplies, refuting Staff’s adjustment related to coal supply at the Bridger plant under a “lower of cost or market” affiliated interest standard.

Staff’s Dave Johnston Plant Fuel Burn Expense Adjustment

Q. How does the Company plan to meet coal supplies for its Dave Johnston plant in 2010?

A. At the time of the TAM filing, the Company estimated that approximately 81 percent of its coal requirements for the Dave Johnston plant would be met from third-party, multi-year contracts and the remaining 19 percent of coal (“Open Position”) would be purchased on the spot market at $10.33 per ton, plus $0.25

per ton for dust suppression and side release, for a total cost of $10.58 per ton. This price represented the forward market price, F.O.B. Mine, of Powder River Basin 8400 Btu coal ("PRB Coal").

Q. Please summarize Staff's proposed adjustment to the Dave Johnston fuel burn expense.

A. Staff proposes to adjust the Dave Johnston fuel burn expense by substituting the forward market price of PRB Coal ($10.58 per ton) for the Open Position, with the Energy Information Administration ("EIA") Average Weekly Coal Commodity Spot Price for the Powder River Basin (8,800 Btu) coal of $9.00 per ton. Staff applies an escalation factor provided by PacifiCorp for certain of its third-party coal supply contracts to the EIA spot price.

Q. Did the Company recently conduct a procurement process to supply the Open Position for the Dave Johnston plant?

A. Yes. PacifiCorp issued a request for proposal ("RFP") to supply the Open Position on March 24, 2009. PacifiCorp selected two bids to fulfill the Open Position with a weighted average cost of $9.61 per ton, plus $0.25 per ton for dust suppression and side release, for a total cost of $9.86 per ton. The weighted average cost of the selected bids is $0.55 per ton higher than Staff's proposed EIA current spot market price.

Q. Does the Commission presume market value for contract prices selected under a competitive procurement process?

A. Yes. Oregon Administrative Code ("OAR") § 860-027-0040 sets forth procedures for obtaining approval of utility transactions with affiliated interests.

Subsection (2)(k) of that rule provides as follows:

> Transfer prices in contracts or agreements for the procurement of goods or services under competitive procurement shall be presumed to be the market value, subject to evaluation of the procurement process.

OAR § 860-027-0040(2)(k)

Although this policy is provided in the context of affiliate transactions, it sets forth a general policy that may be applied to determining market value in this proceeding.

Q. Did the Company include the selected Open Position bid price from the RFP in its August TAM update?

A. Yes. Under the TAM Guidelines adopted by the Commission in Order No. 09-274 (Docket UE 199), PacifiCorp's August TAM update includes new fuel contracts; therefore, the updated net power costs reflects the new contracts recently selected under the RFP for the Open Position. The updating of the Open Position prices renders Staff's adjustment for Dave Johnston fuel burn expense moot.

Staff's Huntington Plant Fuel Burn Expense Adjustment

Q. How does the Company plan to meet coal supplies for its Huntington plant in 2010?

A. For 2010, the Company's affiliate Deer Creek coal mine will deliver 3 million tons of coal at a weighted average cost of $32.44 per ton. Approximately 2.659 million tons will be delivered to Huntington at a weighted average cost of 33.22 per ton. The remaining 0.341 million tons of Deer Creek coal will be delivered to Hunter at a F.O.B. mine cost of $26.50/ton. The remaining 10 percent of the

Huntington plant' s coal will be supplied under a third-party, long-term contract at [redacted] per ton.

Q. Please summarize Staff' s proposed adjustment to the Huntington fuel burn expense.

A. Staff proposes to adjust the fuel burn expense at the Huntington plant by performing a lower of cost or market analysis required for affiliate interest transactions under OAR 860-027-0048. In its analysis, Staff determines the market cost of coal provided at Huntington by averaging third party coal costs at PacifiCorp' s Huntington, Hunter and Carbon plants. Based on this calculation, Staff imputed an average market price of $32.29 per ton.

Q. Please explain the Commission' s transfer pricing policy for affiliate transactions.

A. OAR 860-027-0048 sets forth the Commission' s transfer pricing policy for affiliate transactions and requires that goods purchased from an affiliate be priced at the lower of cost or fair market rate. *See Matter of PacifiCorp for Approval of a Coal Supply Agreement with Bridger Coal Co.*, Docket UI 189, Order No. 01-472 (June 12, 2001). The rule defines " market rate" as " the lowest price that is available from nonaffiliated suppliers for comparable services or supplies." OAR 480-027-0048(1)(i) (emphasis added).

Q. What is the basis for the transfer pricing policy?

A. I understand that the policy is designed to prevent cross-subsidization between unregulated affiliates and the regulated utilities.

Q. Under the agreement between PacifiCorp and Energy West could customers cross-subsidize Energy West's operation costs?

A. No. Under the agreement between Energy West and PacifiCorp, Energy West manages the Deer Creek mine for PacifiCorp. Deer Creek coal costs include Energy West's actual costs to operate and manage the mine for PacifiCorp. Energy West has managed the Deer Creek mine, on behalf of PacifiCorp, for many years and delivered coal at below market prices. Energy West earns no profit under the agreement. There is no credible basis to claim that PacifiCorp's customers are cross-subsidizing the operation costs of Energy West.

Q. Is Staff's determination of the market price for coal at the Huntington plant consistent with the Commission's transfer pricing policy for affiliate transactions?

A. No. As explained above, Staff arrived at a market price of $32.29 by simply averaging third-party coal costs at PacifiCorp's Huntington, Hunter and Carbon plants. In relying on third-party contracts as the "market rate" for coal to be provided at the Huntington plant, Staff has failed to demonstrate that such coal is (1) available at that price; and (2) comparable.

Q. The Commission's transfer pricing policy requires market comparisons to be drawn from <u>available</u> alternate suppliers. Does Staff's market analysis consider this fact?

A. No. The most likely source of available alternate coal supplies to Huntington, however, is the spot market in Utah. There are readily available published prices and forecasts for this spot market. Staff relied upon similar spot market data for its adjustment for coal supply at the Dave Johnston plant, but inexplicably ignored this data for the Huntington plant.

Q. Is the cost of coal from the Deer Creek mine at Huntington well below the forecast Utah spot market price for 2010?

A. Yes. The Utah forecast spot price for 2010 is $48.45 per ton, plus roughly $3-4 per ton for transportation. *See Coal Daily*, July 31, 2009. Deer Creek' s delivered cost of $33.22 per ton is almost $20 per ton less than the Utah spot market price.

Q. Do you agree that the coal provided under the third-party contracts utilized by Staff in its analysis is available at the prices provided in those third-party contracts?

A. No. For example, prices under the Sufco contract (used to supply the Huntington and Hunter plants) are lower due to its early vintage (late 1990s) and are no longer available. The contract is up for an extension in 2011, which will require a price renegotiation. The Company anticipates a price escalation in line with current market prices at the time of renegotiation.

Q. Are there contracts of more recent vintage that demonstrate the unavailability of prices such as those in the Sufco contract?

A. Yes. The Electric Lake contracts provide more contemporary pricing (February 2008), however, even these contracts were executed prior to the more recent escalation in the Utah and Colorado coal markets. The Electric Lake contracts for Skyline, and Dug-Out are priced at $31.93 and $32.76 per ton, respectively. Because these prices are F.O.B. mines, additional transportation costs (ranging from \$3 to \$4 per ton) are required, resulting in a higher total cost per ton than the Deer Creek delivered price of \$33.22 per ton.

Q. Do you agree that the coal provided under the third-party contracts utilized by Staff in its analysis is <u>comparable</u> to coal provided by Deer Creek?

A. No. For example, the Westridge contract (used to supply Hunter) has an extremely low price of [redacted] per ton due to its inferior quality – high ash, high sulfur and lower heat content. It is not considered a "marketable coal[1]" because it cannot be burned by plants without blending it with higher quality coals and incurring additional costs. In comparison, coal from Deer Creek is of a higher quality due to its lower ash, lower sulfur and higher heat content.

Q. As previously discussed, Staff proposes to adjust the cost of Deer Creek coal used at the Huntington plant. Is Deer Creek used to supply coal for any of PacifiCorp's other plants?

A. Yes. The Deer Creek mine supplies coal for use at the Company's Hunter plant and may supply coal to the Carbon plant. Staff's conclusion that Deer Creek coal is below market as supplied to these plants supports the Company's position that Deer Creek coal is also below market as supplied to Huntington. All of the coal from the Deer Creek mine is supplied under the same cost-based contract with Energy West.

[1] Coal marketability is typically defined by heat content and sulfur dioxide content within a specific coal producing region. Per Argus Media's Coal Daily, the Utah coal market conforms to an average heat content of 11,700 Btu/lb. and a sulfur content of 0.9 pounds of SO_2 per mmbtu.

Staff' s Bridger Plant Fuel Burn Expense Adjustment

Q. How does the Company plan to meet coal supplies for its Bridger plant in 2010?

A. For 2010, the Company' s affiliate Bridger mine will provide approximately two-thirds of the Bridger plant' s coal requirements at $33.54 per ton, or at $30.63 per ton excluding the impact of the new accounting standard EITF 04-6. The remaining one-third of the coal will be supplied under the third-party Black Butte contract. The 2010 delivered price of this contract is $30.70 per ton; with lower-priced carryover tonnage from the prior contract, the effective delivered price is $27.76 per ton.

Q. Please summarize Staff' s proposed adjustment to the Bridger fuel burn expense.

A. Staff proposes to adjust the fuel burn expense at the Bridger plant under a lower of cost or market analysis under OAR 860-027-0048. Staff provides several different approaches to determining the market price for Bridger coal supply: (1) averaging the cost of the Black Butte contract and the Kemmerer mine supply contract to the Naughton plant to replace coal supply from Bridger mine' s surface operations (Staff' s first market analysis, producing a cost of $28.73 per ton) or overall coal supply from the Bridger mine (Staff' s fourth market analysis, producing a price of $27.99 per ton); (2) using the cost of the coal from Bridger mine' s underground operations to replace the cost of coal from its surface operations (Staff' s secondary market analysis, producing a cost of $28.88 per ton); and (3) using the price of PRB coal, transported to the plant to replace the cost of Bridger mine's surface operations (Staff's third market analysis, producing a price of $30.49 per ton).

Q. Under the contract between PacifiCorp and Bridger Coal Company, could customers cross-subsidize Bridger Coal Company shareholders?

A. No. Any profit attributable to PacifiCorp's share of Bridger Coal Company is credited back to PacifiCorp as an offset to the contract price. Under this contract, PacifiCorp has acquired coal from the Bridger mine at below market prices for many years. There is no credible basis to claim that PacifiCorp's customers are cross-subsidizing the shareholders of Bridger Coal Company.

Q. Please explain the fundamental concern you have with Staff's analysis of the price of Bridger coal supply.

A. With the exception of Staff's fourth market analysis, in each instance, Staff's analysis is targeted at a single component of the cost of Bridger coal—the cost of coal from surface operations—not the overall price of coal from the mine. This analysis is erroneous on several levels. First, the transfer pricing policy compares the cost of goods transferred with market. It does not provide any basis for reviewing and replacing a single component of the cost of goods transferred as above market and accepting the balance of the costs as below market.

Second, the mine runs as a single operating unit, combining underground and surface operations to produce a blended quality coal on the lowest cost/risk basis. While the surface operation produces less coal than the underground operations (producing a higher per ton price), the surface operations contribute positively to the overall cost/risk profile of the mine by providing additional capacity, flexibility in running the underground operations, a hedge on market prices and support for the common costs at the mine.

Q. The Commission's transfer pricing policy requires market comparisons to be drawn from available alternate suppliers. Does Staff's market analysis consider this fact?

A. No. Staff's primary and fourth market analyses rely on the average price of the Black Butte contract and the Kemmerer mine supply contract to Naughton. With respect to Black Butte, as Mr. Lasich testified in his direct testimony, the Company has contracted for all available coal from the Black Butte mine. Staff has not contested this testimony. See PPL/401 (Staff response to PacifiCorp DR 1.5(b)). The rule defines "market rate" as "the lowest price that is available from nonaffiliated suppliers for comparable services or supplies." OAR 480-027-0048(1)(i) (emphasis added). Under the rule, the Black Butte mine contract price cannot be used as a market proxy because there is no available supply from this mine in 2010.

Q. Is there a second problem with Staff's use of the Black Butte contract price as a market proxy?

A. Yes. Instead of using the actual delivered price for the 2010 Black Butte contract, $30.70 per ton, Staff uses a price that reflects lower priced carryover tonnage from the prior contract. Staff provides no justification for use of this lower price; indeed Staff does not even include a reference to the actual 2010 contract price in its testimony. This case is designed to capture the cost of 2010 coal supply; coal priced under the previous agreement is not now "available" in the market as required by OAR 480-027-0048(1)(i).

Q. Is coal from the Kemmemer mine <u>available</u> to supply the Bridger plant with <u>comparable</u> coal supplies?

A. No, for several reasons. First, the bulk of the output of the Kemmerer mine is already dedicated to supply of the Naughton plant, with the remainder going to supply industrial customers in the region. While the recession may have temporarily freed up some of the coal normally used for industrial supply, this coal supply would be available only on a short-term, non-firm basis, which is not comparable to that now supplied by the Bridger mine.

Second, the Bridger mine coal price includes delivery to the Bridger plant. The Kemmerer/Naughton contract price of $28.23 per ton is non-comparable because it does not include a transportation component. Staff acknowledges that it did not conduct an analysis of the transportation costs associated with the delivery of coal from the Kemmerer mine to the Bridger plant. See PPL/401 (Staff response to PacifiCorp DR 1.6(a)). While the Kemmerer mine is located adjacent to the Naughton plant site, it is approximately 120 miles away from the Bridger plant. The only way to transport short-term, non-firm coal supplies from Kemmerer mine to the Bridger plant is by truck. A conservative estimate of the cost of trucking coal from the Kemmerer mine to the Bridger plant is $15.00 per ton, resulting in a delivered price of $43.23 per ton.

Q. Assuming coal supplies were available from Black Butte and Kemmerer for Bridger's 2010 coal supply needs, what is the average price for these supplies?

A. Averaging the 2010 price from the Black Butte contract of $30.70 per ton and a delivered price of $43.23 per ton from the Kemmerer mine produces a cost of $36.97 per ton. This is higher than Bridger's coal supply cost of $33.54 per ton.

Q. Staff's secondary market analysis proposes to replace the costs of Bridger's surface operations with the cost of underground operations. Is there additional coal available from Bridger's underground operation to supply the Bridger plant?

A. No. Staff acknowledges that underground coal at Bridger is not available to replace surface mining operations at Bridger. Staff/200, Dougherty/16, lines 17-19. In any event, the underground coal is not available from a "nonaffiliated supplier" as required by OAR 480-027-0048(1)(i). The Commission's rule is designed to compare the costs of sales or services from affiliates to the price of sales or services from non-affiliates to prevent cross-subsidization. It is not designed to compare individual cost components embedded in the affiliate's overall price to arbitrarily reduce that overall price.

Q. Staff's third market analysis proposes to replace the costs of the surface mining operations at Bridger with the delivered market price of PRB coal provided in Mr. Lasich's direct testimony. Is this an appropriate comparison?

A. No. Mr. Lasich properly compared the delivered price of PRB coal to the overall price of coal from the Bridger mine and showed that costs from the mine were more than $5 per ton below available, comparable PRB supplies. Staff's testimony "does not disagree with the analysis," but indicates that the comparison concerning lower of cost or market pricing should be to the costs of the surface mining operations only, not the overall costs of coal supply from the Bridger mine. Staff/200, Dougherty/17. For all of the reasons I have already stated, the Company objects to the Staff's application of market price analysis to a single component of the costs of Bridger coal supply. Additionally, the Bridger plant lacks the physical capacity to accept significant new volumes of rail delivered coal. In order to replace the surface operations with PRB coal, the Company would need to make significant new infrastructure investments to its receiving facilities. This investment could not be justified on the basis of a short-term cost fluctuation, such as that caused by application of EITF 04-6.

Q. Please explain how EITF 04-6 impacts Bridger mine's 2010 costs.

A. As Mr. Lasich explains in his testimony, this accounting standard changes the Company's traditional accounting practice by linking coal stripping costs with coal that is extracted in a given year. Mr. Lasich also explains that the Company intends to file accounting applications in all states seeking to establish a regulatory asset balancing account that would reduce the volatility of coal costs from the Bridger mine. This treatment would reflect the accounting practices prior to the implementation of EITF 04-6 in 2006.

EITF 04-6 increases the costs from Bridger surface mining operations in 2010, from approximately $39 per ton to $57 per ton, and an increase in the overall cost of Bridger coal from $30.63 per ton to $33.54 per ton. As noted in Staff's footnote 22, the 2009 weighted cost of Bridger coal was $30.57 per ton. Viewed in this manner, it is clear that the 2010 cost increase at the Bridger mine is largely related to EITF 04-6. The cost increase is not a function of cross-subsidization or imprudence.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UE-207
Exhibit PPL/401
Witness: Bret C. Morgan

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Bret C. Morgan

Responses to PacifiCorp Data Requests

August 2009

Request:

1.5 See Staff/200, Dougherty/13, line 6. Please confirm that Staff's "lower of cost or market" analysis did not use actual 2010 contract price of the Black Butte contract but instead used a price that reflects carryover tonnage from the previous, lower-priced contract.

a. If Staff is using the Black Butte contract as a market proxy, please explain why the actual 2010 contract price is not a more accurate reflection of 2010 market prices than a blended price that includes carryover coal from an earlier contract.

b. Does Staff contest the following testimony at PPL (TAM)/200, Lasich/6, Lines 9-10: "The Company has contracted for all available supplies from the Black Butte Mine"? If so, please provide all evidence relied upon to contest this statement. If not, please explain why the Black Butte contract is an appropriate source of market data for purposes of Staff's "lower of cost or market" analysis.

Response:

Staff's lower of costs or market (LCM) used the Black Butte price as provided by the Company in PacifiCorp's response to Staff Data Request No. 36.

a. Staff's Data request No. 36c specifically requested, "In the following table (Excel) format, please provide the following information. In addition, please indicate if the contract is indexed by the CPI, PPI, or combination of CPI and PPI."

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

As such, Staff was using PacifiCorp's market data.

b. Staff never contested this statement. Please see Staff/200, Dougherty/10 lines 3 – 12.

PPL (TAM)/200. Lasich/3 states, "The Company obtains approximately a third of the coal necessary to fuel the Bridger Plant from the Black Butte Mine." Since PacifiCorp uses the mine for approximately one-third of coal utilized by Bridger, Black Butte Mine is an appropriate source of market data.

Request:

1.6 See Staff/200, Dougherty/13, lines 7-9. Please confirm that Staff's "lower of cost or market" analysis did not include transportation costs associated with delivering coal from the Kemmerer mine (located at the Naughton plant) to the Bridger plant, located approximately 120 miles away.

a. Please provide all analysis Staff has conducted of the transportation costs associated with delivery of coal from the Kemmerer mine to the Bridger plant.

b. Does Staff contend that coal is available from the Kemmerer mine to supply the Bridger plant? If so, please identify the amount of coal available and the term for which it is available. If not, please explain why the Kemmerer/Naughton contract is an appropriate source of market data for purposes of Staff's "lower of cost or market" analysis.

Response:

Staff used the Naughton cost as provided in PacifiCorp's confidential responses to Staff Data Requests Nos. 5 and 36.

a. Staff did not conduct such an analysis. Please see PacifiCorp's confidential response to Staff Data Request No. 36c on FOB method for third party mines.

b. OAR 860-027-0048 addresses lower of cost or market pricing. It does not address a company's penetration or participation in the market. As previously stated, PacifiCorp in its confidential responses to Staff Data Requests Nos. 5 and 36 provides market prices in the GRB. PacifiCorp's confidential response to Staff Data Request No. 6 provides quantity of coal delivered from mines in the GRB.