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January 20, 2010

Via Electronic Filing and U.S. Mail

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

RE: Docket No. UE 214 – In the Matter of IDAHO POWER COMPANY 2010 Annual Power Cost Update.

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

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

c: UE 214 (Service List (parties)

PUBLIC UTILITY COMMISSION
OF OREGON

UE 214

STAFF OPENING TESTIMONY OF

ED DURRENBERGER
MICHAEL DOUGHERTY

In the Matter of
IDAHO POWER COMPANY
2010 Annual Power Cost Update

<u>REDACTED VERSION</u>
January 20, 2010

CASE: UE 214
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

January 20, 2010

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

A. My name is Ed Durrenberger; I am a Senior Utility Analyst for the Electric & Natural Gas Division of the Public Utility Commission of Oregon (OPUC). My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This testimony addresses issues with the Idaho Power Company's (Idaho Power or company) October update portion of their 2010 Annual Power Cost Update (APCU).

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes, I include two pages of exhibits as Exhibit Staff/102.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I intend to discuss the following issues:

Issue 1, Load growth adjustment
Issue 2, Hoku power contract adjustment
Issue 3, Unexecuted PURPA power purchase agreements adjustment
Issue 4, Normal Hydro output adjustment for aalmon flow augmentation and declining reach gains
Issue 5, Water water rental agreement benefit adjustment.

ISSUE 1: LOAD GROWTH

Q. PLEASE EXPLAIN THE LOAD GROWTH ISSUE.

A. Idaho Power estimates what the load growth will be for the 2010 power cost year[1] as part of its UE 214 October update filing. The load that was modeled in this filing is 1,817 average megawatts (aMW). Although this value is 3.2 percent (3.2%) lower than the system load used last year in the October update filing, it is nearly identical to the load forecast in 2008 (1,825 aMW) which was made before the current economic downturn started. I do not agree with the company load estimate for the following reasons:

- The recently filed Integrated Resource Plan (IRP), LC 50, contains sales and load tables (Appendix A) that indicated actual loads for 2008 were 1,798 aMW and forecasts a load decrease in 2009 and then 2010 loads recovering back up to only 1,797 aMW.
- The U.S. Energy Information Administration (EIA) reports a decline of approximately five percent (5%) in retail electricity sales for Oregon since the start of the recession, and
- Other regulated utilities in Oregon have reported decreasing loads in 2009, primarily due to decreasing industrial loads that are not expected to fully recover in 2010.

[1] For the purposes of the Idaho Power's APCU, the power cost year modeled runs from April 2010 through March 2011.

Q. WHAT DO YOU PROPOSE?

A. I propose that Idaho Power adopt the same load in its UE 214 filing as was projected in its IRP filing for 2010 firm loads: 1,797 aMW. [2]

ISSUE 2: HOKU POWER CONTRACT ADJUSTMENT

Q. PLEASE EXPLAIN THIS ISSUE.

A. Hoku Scientific (Hoku) is building a production plant in Pocatello Idaho to make materials used in the manufacture of solar cells. Idaho Power and Hoku have negotiated a new single customer rate schedule under which this new incremental load will be served. I have reviewed the Hoku agreement and have no issue with the terms and conditions under which this new large industrial load will be served. My issue is there appears to be a large amount of uncertainty as to when Hoku will actually start production and will need the large load for which it has arranged. Hoku originally announced on its web site that the Pocatello plant would begin production in 2007, however construction of the plant has not proceeded as expected and the plant is not yet completed. In December 2009, the "Wall Street Journal" reported that a Chinese solar cell manufacturer had acquired controlling interest in the plant and that it would be seeking additional financing to complete the construction. Despite all this uncertainty, Idaho Power has modeled its base rates for 2010 to include the loads and revenues from the first block portion of the Hoku service agreement. This new and uncertain load represents roughly 2% of the sales to customers forecast in the October update. Considering the delays in completing the plant

[2] *See* Idaho Power Company 2009 Integrated Resource Plan, LC 50, Appendix A, page 48.

that have occurred so far, and the changes of ownership, I do not consider the Hoku power sales to be known and measurable event for the 2010 power cost year. The load and revenue from the Hoku service agreement should be removed from the base rates at this time.

Q. WHAT WILL THIS ADJUSTMENT DO TO THE OCTOBER BASE RATE UPDATE?

A. Idaho Power will need to remove the line adjustment it has made for the Hoku revenue. The power sales to customers will also need to be adjusted to remove the Hoku first block load. Finally, the AURORA power cost model will need to be run to determine the overall effect of the adjustment.

Q. WHAT DO YOU PROPOSE IF THE HOKU PLANT STARTS UP AS CURRENTLY MODELED AND BEGINS TO TAKE POWER ACCORDING TO ITS ELECTRIC SERVICE AGREEMENT?

A. If Hoku starts up before the March update, the company can simply include the new load and revenue as it currently has done to the power cost model run to be reflected in the base rate update.

Q. WHAT HAPPENS IF THERE IS A DELAY IN THE START UP BUT THE HOKU PLANT BEGINS TAKING SERVICE SOME TIME DURING THE 2010 POWER COST YEAR?

A. The power cost mechanism has a true-up provision where actual power costs are measured against power costs collected in rates. Ideally the incremental power costs due to the load that would occur with the plant startup and operation would be recovered in the rates collected under the terms of the

Hoku electrical service agreement. If there is any discrepancy in the actual power costs and the power costs collected in rates, the variance will be handled under provisions of the Idaho Power PCAM true-up mechanism.

ISSUES 1 AND 2: SUMMARY

Q. PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENT WITH RESPECT TO TEST YEAR LOADS.

A. I propose that the average load used in the determination of the October update of base rates include the following adjustments:

Item	Original filing	Staff Proposed	Adjustment
2010 Average load	1,817 aMW	1,797 aMW	-20 aMW
Hoku Power Sales	included	-39 aMW	-39 aMW
Total	1,817 aMW	1,758 aMW	-59 aMW

<u>ISSUE 3: UNEXECUTED PURPA POWER PURCHASE AGREEMENTS</u>

Q. WHAT IS THIS ISSUE?

A. Idaho Power has modeled an 85% increase in PURPA contract costs for 2010, which amounts to approximately $54 million. The company provides two reasons for this. First, the company claims there are a number of new PURPA projects where it has entered into “power purchase agreements” (PPAs) with the counterparty that have not yet come on line but are expected to enter into production during the power cost year. Second, the company has re-priced some of its existing PURPA qualifying facility (QF) contracts to reflect a

Commission requirement that actual PURPA power costs be reflected in rates rather than levelized power costs (correcting an error in the customer's benefit with the previous October update).

I agree with the company's the second point, that the Commission has required a non-levelized pricing methodology. In its Order 85-010 the Commission rejected any sort of levelizing of variable and fixed operation and maintenance costs for QF contracts.

I take issue, however, with including in the company's filing energy costs associated with QF PPAs that have not yet attained commercial operation status. Although a PPA may identify an actual start-up date, it is not appropriate to include such energy costs as known and measurable when actual commencement of the operation is not certain. There is cause to doubt that these QFs will necessarily start up as claimed. For instance, Idaho Power's October update filing in 2007 for the 2008 power cost year is instructive on this point. At that time a number of new PURPA QFs were forecast to begin operations in the coming year. The dollar value of the PURPA contracts was forecast to be double the level then in rates. But in the next October update, in 2008 for the power cost year in 2009, PURPA contracts went down dramatically, dropping to just 73% of the amount previously forecasted. The company's accompanying testimony explained that the dramatic drop was caused by new PURPA contracts failing to meet their on-line target dates. Now this year's October update has dramatically higher PURPA costs, this time over 80% higher than the previous year.

Testimony from the company indicates that several PURPA projects, mostly wind that are not yet operational, are expected to come on line during the April 2010 to March 2011 period. Considering the recent track record of QFs not coming on-line as expected, I propose that new PURPA contracts that have not yet attained commercial operating status at the time of the AURORA power cost model run not be considered known and measurable and, therefore, be excluded from the filing.

ISSUE 4: NORMAL HYDRO FLOW ADJUSTMENT FOR SALMON FLOW AUGMENTATION AND DECLINING REACH GAINS

Q. PLEASE EXPLAIN THIS ISSUE?

A. Idaho Power has made some adjustments to the normal hydro generation that affects the timing of output from its hydro system. When compared with the normal hydro generation filed last year in UE 203, there has been a shift in the timing of the hydro output. In the current filing there is more than normal amount of hydro output in May and June and less than normal hydro output in July and August (hereafter referred to as "the shift" or "stepwise change"). Overall the annual hydro output is consistent with the normal output from previous October updates. However, changing the timing of the generation profile, as Idaho Power has done, causes more surplus sales in low price months and more market purchases in higher price months. The initial testimony did not discuss the shift, but in response to Staff Data Request 17 (*See* Exhibit Staff/102 Durrenberger /1 and 2), Idaho Power explained that the normal hydro generation was shifted to accommodate an earlier release of water for Salmon Flow Augmentation as requested by the U.S. Bureau of Reclamation (USBR). The company also indicated in Data Response 17 that there was a small adjustment decreasing overall normal hydro output because Snake River tributary flows were trending downward, reducing the overall river system flow available for hydro generation.

Q. DO YOU AGREE WITH THESE CHANGES?

A. No. Idaho Power has not shown any data that supports the decline in generation in the July-August period, nor, for that matter, the increase in generation in the May and June period. In addition, I do not believe early fish augmentation flow and its expected change to the generation output profile ought to make a stepwise change in the normalized hydro generation. Absent actual data that documents permanent changes to the generation profile, the salmon augmentation flow should be modeled as a single year change to be averaged into the 80 plus years of water flow and hydro generation data. Furthermore, Idaho Power has presented no evidence in this filing supporting the assumption that the declining reach flows were permanent as opposed to being caused by variability in weather or some other factor that could reverse itself in the future. Finally, when the PCAM methodology was approved by the Commission in UE 195, Idaho Power represented its normalized hydro generation as the average of the hydro generation calculated from water year flows beginning in 1928, adjusted by the most recently issues Depleted Stream Flow Study report. The report is updated periodically to account for the change in the hydro generation output caused by such matters as fish augmentation and declining reach gains. Only after a new report comes out should Idaho Power automatically update normal hydro generation for the purposes of the PCAM. All the other hydrological events were intended to update the individual annual water flows and generation and become part of the average.

I do not know what shifting of the timing of hydro generation means in terms of any sort of adjustment to base power supply expenses. I have not yet asked the company to model this change with a new power cost model run but I would expect the change to be minimal.

ISSUE 5: WATER RIGHTS LEASE AGREEMENT BENEFIT ADJUSTMENT

Q. WHAT IS THIS ISSUE?

A. Idaho Power leased rights for water to be released from the American Falls Reservoir in August and September. The company has not modeled either the cost or benefit of this water lease in its power cost model. I recommend that Idaho Power incorporate the costs and benefits of this water lease into the power cost model for setting the October update of base rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

CASE: UE 214
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

January 20, 2010

WITNESS QUALIFICATION STATEMENT

NAME:	Ed Durrenberger
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst, Electric and Natural Gas Division
ADDRESS:	550 Capitol St. NE, Ste. 215, Salem, Oregon 97301
EDUCATION:	B.S. Mechanical Engineering Oregon State University, Corvallis, Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission of since February of 2004. My current responsibilities include staff research, analysis and technical support on a wide range of electric and natural gas cost recovery issues with an emphasis on electricity and fuel costs.
OTHER EXPERIENCE:	I worked for over twenty years in industrial boiler plant engineering, maintenance and operations. I this capacity I managed plant operations, fuel supplies and utilities, environmental compliance issues and all aspects of boiler machinery design, installation and repair. I have also worked as a production manager and machine shop manager for an ISO certified high tech equipment manufacturer servicing the silicon wafer fabrication and biomedical business sectors.

CASE: UE 214
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

January 20, 2010

STAFF'S DATA REQUEST NO. 17:

The 2010 October update shows lower hydro generation output for July and August that the previous October Updates. Please explain what happened to the most recent water year hydro generation that would explain this change in hydro output.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 17:

The 2010 October Update showed several differences in hydro generation from the 2009 October Update. These differences are directly related to changing conditions and flows on the Snake River. Changing flows occur for two primary reasons: (1) changes to the timing of salmon flow augmentation and (2) the incorporation of long-term declines in reach gains in the Snake River.

Changes in Salmon Flow Augmentation

The 2010 October Update estimates represent not just declines in generation in the months of July and August but an actual shift in generation from those months to May and June. This shift can be attributed to changes in the timing of salmon flow augmentation. In the *Biological Assessment (BA) for Bureau of Reclamation Operations and Maintenance in the Snake River Basin Above Brownlee Reservoir*, released in August of 2007, the Bureau of Reclamation ("USBR") discusses changes in the timing of releases from Snake River reservoirs for flow augmentation. The change in the BA shifted augmentation flows from summer to spring. In the BA the USBR states:

> Based on these observations and NMFS' recommendations, Reclamation has investigated shifting reservoir releases for flow augmentation to earlier in the spring subject to confirmation of the biological benefits by NMFS.

This shift is a major departure from the July, August, and September time frame in which augmentation flow releases have occurred in previous years. In late 2008 and early 2009, Idaho Power Company ("Idaho Power") staff discussions with USBR personnel indicated that the USBR would attempt to shift flow augmentation releases to the May and June time frame in the 2009 water year. To reflect this shift in flow augmentation releases, Idaho Power staff modeled flow augmentation releases in May and June. Idaho Power staff reviewed historic data and calculated the volume of water available for flow augmentation in the 1928 through 2005 period (flows for this time frame provide long-term estimates of future flows). This volume of water was then moved from the traditional July, August, September time frame to May and June. This shift substantially changes the power generation capabilities at Idaho Power facilities, resulting in higher generation in May and June and lower generation in July and August.

In the spring of 2009, the USBR implemented the spring shift in flow augmentation. Flow augmentation releases were delayed during the spring of 2009 due to record rainfall and high stream flows, but the USBR was successful in releasing all augmentation flows by mid- to late July.

Incorporation of Declining Reach Gains

Generation estimates also show a slight decrease in overall generation for the 2010 October Update, which is caused by declining reach gains in the Snake River Basin. Long-term records for spring discharge of tributaries to the Snake River basin have been in decline since the late 1950s. In order to provide a more accurate estimate of long-term flows in the Snake River, these declines were incorporated into estimates of flow on the Snake River. Yearly declines are not large but their incorporation into long-term flow estimates is important because the cumulative declines over several years can have a significant impact on river flows and subsequent hydro generation.

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

OPENING TESTIMONY

January 20, 2010

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 200

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 09 - 418. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 214 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

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

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I describe my adjustments to Idaho Power Company's (Idaho Power) power supply costs concerning its three coal plants: Bridger, Boardman, and Valmy as listed in Idaho Power/101, Wright/1.

Q. HAVE YOU PREPARED ANY EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared:

Confidential Exhibit Staff/202, consisting of 2 pages;

Exhibit Staff/203, consisting of 21 pages; and

Confidential Exhibit Staff/204, consisting of 2 pages.

Q. PLEASE PROVIDE A SUMMARY OF YOUR ADJUSTMENTS.

A. The following table summarizes my adjustments to Idaho Power's power supply costs concerning its three coal plants: Bridger, Boardman, and Valmy as listed in Idaho Power/101, Wright/1.

Table 1 – Summary of Staff Adjustments

Plant	**Exhibit Idaho Power/101, Wright/1**	**Staff**	**Adjustment**
Bridger	$105,249,100	$89,664,839	$15,584,261
Boardman	$6,773,800	$6,773,800	$0
Valmy	$50,266,500	$50,266,500	$0
Total Adjustment			$15,584,261
Total Oregon Adjustment (.0464 allocation)			**$723,110**

Q. PLEASE SUMMARIZE THE ANALYSES SUPPORTING YOUR RECOMMENDED ADJUSTMENTS.

A. Bridger– Because Bridger receives coal from an affiliated interest coal mine; I performed several lower-of-cost-or-market (LCM) analyses pursuant to Oregon Administrative Rule (OAR) 860-027-0048, *Allocation of Costs by an Energy Utility*. The primary LCM analysis results in an Oregon adjustment of $723,110 to the Idaho Power's Bridger power supply costs.

Boardman and Valmy – These coal plants are supplied by third party mines. I examined the costs per ton of coal and the tons of coal delivered. As a result of my analysis, I do not have any adjustments to the Boardman and Valmy power supply costs.

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

A. Yes. Concerning coal costs from affiliate, Bridger Coal Company (BCC) supplied to Bridger, I performed four LCM analyses. My primary analysis, as shown in the above table, results in an Oregon adjustment of $723,110 for Bridger power supply costs. A first alternative analysis results in an Oregon adjustment of $691,354 for Bridger power supply costs. I also performed a second and third alternative analysis that I did not use as recommended adjustments. These analyses are explained later in testimony and are shown in Staff Confidential Exhibit/202, Dougherty/1-2. The following table shows the power supply costs adjustments based on two LCM analyses concerning BCC.

Table 2 – Alternative Recommended Oregon Adjustments

Primary Adjustment	$723,110
Alternative Adjustment	$691,354

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

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

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

> accounts at the affiliate's cost or the market rate, whichever is lower.

Under the rule, supplies that are not under an approved rate shall be recorded in the energy utility's accounts at the lower of the affiliate's cost or market rate. BCC is an affiliate of Idaho Power. As a result, this transfer pricing rule is relevant concerning pricing of coal supplied from BCC to Bridger.

Q. PLEASE EXPLAIN THE AFFILIATED RELATIONSHIP BETWEEN IDAHO POWER AND BCC.

A. According to Idaho Power s 2008 Affiliated Interest Report, Idaho Energy Resources Co. (IERCO) is a regulated subsidiary of Idaho Power in all jurisdictions including Oregon. IERCO owns 33.33 percent of BCC, the coal mining joint venture with Pacific Minerals Inc (PMI),[1] which is a subsidiary of PacifiCorp. The Commission approved a coal supply agreement between IERCO and Idaho Power in Commission Order No. 91-567 (UI 107), dated April 25, 1991.

Q. PLEASE DISCUSS BCC'S OPERATIONS AND COSTS.

A. BCC's overall costs are a weighted cost of surface mining operations and underground mining operations. The average BCC cost per ton for the April 2010 to March 2011 timeframe is [redacted].

Q DID COMMISSION ORDER NO. 91-567 (UI 107) RESERVE THE RIGHT TO REVIEW FOR REASONABLENESS ALL FINANCIAL ASPECTS CONCERNING PRICING OF COAL FROM BCC?

A. Yes. The Commission Order states:

[1] PMI owns the remaining 66.67 percent of BCC.

> The transfer price for the coal which is provided to Bridger to Idaho shall be billed at actual cost. Cost in this case is equivalent to market for the services. Since all of IERCO's results of operations are merged with and made part of Idaho's for ratemaking, there is no possibility of cross-subsidization.[2]

The order also states on page 5:

> The Commission reserves the right to review for reasonableness all financial aspects of this arrangement in any subsequent rate proceeding.[3]

Q. IF THE ORDER INDICATES THAT COST IN THIS CASE IS EQUIVALENT TO MARKET AND THAT THERE IS NO POSSIBILITY OF CROSS-SUBSIDIZATION, WHY DO YOU RECOMMEND AN ADJUSTMENT?

A. I made an adjustment because BCC's costs are higher than the current market cost. Staff's memo in UI 189, Commission Order No. 01-472 (PacifiCorp's affiliated interest agreement with PMI) provides a description concerning the historical costs of BCC and states:

> The company (*PacifiCorp*) states that BCC coal provides it with advantages such as a consistently reliable coal source and a minimization of fuel transportation and handling costs. Historically, from 1990 through 1999, the average cost of coal provided by the Coal Supply Agreement ranged from $3 to $9 per ton less than the average market price of Southern Wyoming coal delivered to the plant.[4]

However, after calculating four LCM analyses, my review indicates that BCC's costs are no longer below market costs for the Green River Basin (GRB) in Southern Wyoming. Therefore, there was a substantial change in costs that results in BCC's cost being higher than market. Although there is no cross-

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[2] Commission Order 91-567 (UI 105), at 4. *See* Exhibit Staff/203, pages 1 – 5.
[3] Id, at 5. *See* Exhibit Staff/203.
[4] Commission Order No. 01-472 (UI 189). Appendix A, page 2. *See* Exhibit Staff/203, page 9.

subsidization between IERCO and Idaho Power, customers are paying a higher cost for coal being delivered by BCC to Bridger than the “market” (Black Butte Mine) cost of coal, which is also delivered to Bridger.

Q. IN UE 207, PACIFICORP STATED IN PPL (TAM)/200, LASICH/6[5] THAT THERE IS NO ADDITIONAL (COAL) CAPACITY IN THE AREA TO SUPPLY THE BRIDGER PLANT. IN LIGHT OF THIS TESTIMONY, SHOULD THE COMMISSION STILL CONSIDER USING THE TRANSFER PRICING POLICY CONCERNING IDAHO POWER AND BCC?

A. Yes. OAR 860-027-0048 applies to pricing and a market. Based on information provided by Idaho Power in confidential responses to Staff’s Data Requests Nos. 1 and 2,[6] there is a market and pricing for coal in the GRB. Idaho Power uses this market supplied coal for approximately one-third of the coal utilized by Bridger. Therefore, the Commission should use the LCM standard pursuant to OAR 860-027-0048. The rule defines market rate as (emphasis added):

> “the ***lowest*** price that is ***available*** from nonaffiliated suppliers for comparable services or supplies.”[7]

1. Lowest Price – Because Idaho Power receives coal from a third-party mine to supply Bridger, there is adequate data, which clearly shows there is a lower nonaffiliated price for coal in the Green River Basin (GRB) area of Wyoming. The nonaffiliated Black Butte Mine (Black Butte) average

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[5] Included in Exhibit Staff 203, page 13.
[6] Included in Confidential Exhibit Staff 204.
[7] OAR 860-027-0048(1)(i).

delivered coal prices for coal supplied to Bridger [redacted] is significantly lower than the BCC mine delivered coal costs to Bridger at [redacted].[8]

2. Availability – The fact that nonaffiliated Black Butte supplies approximately one-third of Bridger clearly demonstrates that a nonaffiliated supply is available. Additionally, Commission Order No. 79-754, page 17, refers to the PacifiCorp's position on third-party availability in the GRB and states (emphasis added):

> "(2) Unlike the telephone affiliates, an ***alternate market exists for coal sold to PP&L*** at a price higher than the price charged PP&L ratepayers."[9]

Q. HAS IDAHO POWER DISCUSSED COST DRIVERS CONCERNING BCC COAL?

A. Yes, but Idaho Power focuses on long-term coal supplies that expired at the end of 2009.[10] In contrast, PacifiCorp explained certain changes in BCC's costs in PPL (TAM)/200, Lasich/4 and 5 (UE 207) by stating:

> For many years, BCC was able to extract coal at the Bridger surface mine using low-cost highwall mining. The mine has now reached the stage, however, where BCC has replaced this production method with higher-cost dragline mining to properly steward the resources of the mine. Additionally, current accounting pronouncement EITF04-6 requires that production costs be assigned only to extracted coal, not coal that is uncovered but remains in the pit. This contributes to higher costs in 2010 because more coal is scheduled to be uncovered than will be extracted; the opposite will be true in a year when previously uncovered coal is ultimately extracted.[11]

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[8] Staff notes that in PacifiCorp's UI 189 application, PacifiCorp on page 5, footnote 2, specifically stated that BCC and Black Butte "are of comparable quality." See Exhibit Staff/203, page 14.
[9] Included in Staff Exhibit/203, page 15.
[10] Idaho Power/100, Wright/1.
[11] Included in Exhibit Staff/203, pages 16 and 17.

As can be seen from the above statement, one of the cost drivers is an accounting requirement concerning extracted coal that BCC (and other mines) must comply with. As an example of the effect of the accounting requirement, PacifiCorp stated in UE 207 that PacifiCorp's 2010 test period cost of BCC would be approximately $30.63 per ton without EITF 04-6 as compared to $33.54 per ton with EITF 04-6.[12]

Q. PLEASE LIST THE LCM ANALYSES THAT YOU PERFORMED.

A. Because I had concerns with the level of certain cost components embedded in the BCC's weighted costs, I performed four analyses as follows. These analyses are explained in greater detail later in testimony.

1. Primary Analysis – Replaced BCC surface operations costs with market (Black Butte) average (spot, deferred, and transportation) costs and maintained the BCC underground costs to achieve a total BCC cost for ratemaking purposes.

2. First Alternative Analysis - Replaced BCC surface operations costs with market (Black Butte) spot and transportation costs (removed lower cost deferred tonnage) and maintained the BCC underground costs to achieve a total BCC cost for ratemaking purposes.

3. Second Alternative Analysis (not recommended) - Replaced BCC surface operations costs with BCC underground costs and maintained the BCC underground costs to achieve a total BCC cost for ratemaking purposes. This resulted in all of BCC's costs being determined by the cost of underground operations.

4. Third Alternative Analysis (not recommended) – Set BCC costs at the market (Black Butte) average (spot, deferred, and transportation) costs for both surface and underground operations to achieve a total BCC cost for ratemaking purposes.

[12] Included in Exhibit Staff/203, page 18.

Q. PLEASE EXPLAIN YOUR PRIMARY LCM ANALYSIS.

A. In my primary market analysis, I used the actual BCC underground mining operations tons and cost and replaced the BCC surface mining operations costs with the average Black Butte cost (spot coal, deferred coal, and transportation)[13] for each month April 2010 to March 2011.[14] I used the average cost to allow customers to achieve the benefits of the deferred coal. The deferred coal represents the contract price of $11.07 per ton for coal to be delivered in 2010 from the Black Butte mine (stand-alone price per ton). The tonnage to be delivered in 2010 was deferred or delayed from prior years, either because of decreased coal requirements at Bridger or force majeure events.[15] Black Butte coal is an excellent market proxy for BCC's surface operations because:

- Black Butte will provide [redacted] thousand tons of coal (Idaho Power's share) to the Bridger coal plant in the April 2010 to March 2011 timeframe;
- Black Butte coal also accounts for approximately one-third of the coal burned by Bridger; and
- Black Butte is also a surface operation mining operation and is of comparable quality to BCC surface coal.

I used the underground mining operations in this analysis because it is an essential part of BCC's operations, comprising approximately [redacted] percent of

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[13] "Spot" refers to the contract price.
[14] Surface coal was not utilized in all twelve months. As such, I only substituted the monthly Black Butte costs during the months surface coal was used at Bridger. *See* Confidential Exhibit Staff/202.
[15] Idaho Power's response to Staff Data Request No. 20. Included in Exhibit Staff/203, page 19.

coal produced by BCC. Because Idaho Power did not provide a breakdown between tons supplied by both the surface and underground operations, I used the ratio ([redacted] percent) of surface coal provided in PacifiCorp's UE 207 filing. This is a reasonable approach because Bridger is jointly operated by PacifiCorp and Idaho Power. As a result of using the market proxy for BCC's surface operations and including the costs of the underground operations, I calculated a $15,584,261 (system-wide) adjustment to Bridger power supply costs as highlighted in the following table. The complete calculation is shown in Confidential Exhibit Staff/203, Dougherty/1.

Table 3 – Recommended Bridger Power Cost Supply Expense

Coal Source	**Cost**
Adjusted BCC Price	[redacted]
Third Party Coal (Black Butte Mine)	[redacted]
Total Bridger Power Cost Supply	**$89,664,839**
Power Cost Supply from Idaho Power/101, Wright/1	$105,249,100
Adjustment - LCM	**$15,584,261**

Using Idaho Power's allocation Oregon allocation of 0.0464, the Oregon allocated adjustment is $723,110.

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

A. The Commission should accept my primary recommendation because:

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

2. The recommendation uses the April 2010 through March 2011 market (Black Butte) cost of coal being supplied to Bridger as a substitute for surface operations; and

3. The recommendation uses BCC's underground costs in order to recognize an underground component of total costs as BCC has both a surface and underground operation.

Q. PLEASE EXPLAIN YOUR FIRST ALTERNATIVE MARKET ANALYSIS.

A. In my first alternative analysis, I follow the same process as the primary market analysis except that I replace the BCC surface operations with Black Butte's spot and transportation costs. This analysis does not utilize the less expensive deferred price. Because the less expensive deferred coal was not used in the first alternative market analysis to reflect the carry-over tonnage, this first alternative recommended Bridger power supply cost adjustment of $14,899,869 is lower than the primary recommended adjustment. The following table highlights the Bridger power supply cost using the BCC underground mining operations and substituting the surface operations with Black Butte's spot and transportation costs. The complete calculation is also shown in Confidential Exhibit Staff/202, Dougherty/1.

Table 4 – First Alternative Market Analysis - Bridger Power Cost Supply Expense

Coal Source	**Cost**
Adjusted BCC Price	[redacted]
Third Party Coal (Black Butte Mine)	[redacted]
Total Bridger Power Cost Supply	**$90,349,231**
Power Cost Supply from Idaho Power/101, Wright/1	$105,249,100
First Alternative Adjustment - LCM	**$14,899,869**

Using Idaho Power's allocation Oregon allocation of 0.0464, the Oregon allocated adjustment is $691,354. I used this as an alternative and not primary adjustment because customers should receive the benefits of the lower cost of deferred coal.

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

A. My second alternative market analysis uses the cost of BCC's underground operations. In this analysis, I replaced the BCC surface mining operations with the underground mining operations cost per ton. As previously mentioned, the underground operations comprise approximately [redacted] percent of total BCC coal, making it the primary source of coal being supplied by BCC. Because there are no other underground sources in the GRB, BCC's underground operation is the only pricing available to use as a market price. The complete calculation is also shown in Confidential Exhibit Staff/202, Dougherty/2.

Table 5 – Second Alternative Market Analysis - Bridger Power Cost Supply Expense

Coal Source	**Cost**
Adjusted BCC Price using 100% Underground	[redacted]
Third Party Coal (Black Butte Mine)	[redacted]
Total Bridger Fuel Burn Expense	**$88,697,476**
Power Cost Supply from Idaho Power/101, Wright/1	$105,249,100
Adjustment – LCM (Not recommended)	**$16,551,624**

Using Idaho Power's allocation Oregon allocation of 0.0464, the Oregon allocated adjustment is $767,995. I used this as an alternative and not primary adjustment because a surface component of costs should be recognized in the weighted costs. While this adjustment is provided for Commission consideration, I do not believe this alternative is reasonable, given that the surface component of costs is not recognized, and thus should not be adopted.

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

A. In my third alternative market analysis, I substituted the Black Butte coal (spot, deferred, transportation) for all of Bridger's operations including the underground operations. As a result of this lower cost per ton, this analysis would result in a $6,894,461 system-wide adjustment to Idaho Power s Bridger power supply cost. The following table highlights the Bridger power supply cost using third party coal. The complete calculation is also shown in Confidential Exhibit Staff/202, Dougherty/2.

Table 6 – Third Alternative Market Analysis - Bridger Fuel Burn Expense

Coal Source	**Cost**
Adjusted BCC Price	[redacted]
Third Party Coal (Black Butte Mine)	[redacted]
Total Bridger Fuel Burn Expense	**$98,354,639**
Power Cost Supply from Idaho Power/101, Wright/1	$105,249,100
Adjustment – LCM (Not recommended)	**$6,894,461**

Using Idaho Power's allocation Oregon allocation of 0.0464, the Oregon allocated adjustment is $319,903. As previously mentioned, this analysis does not include an underground component. As a result, I did not include this LCM analysis as a recommended cost concerning Bridger power cost supply expense. As previously mentioned, the underground mining operations are an essential part of BCC's operations and the cost of this operation should be reflected in BCC's total costs under any LCM scenario.

Q. IN BOTH THE PRIMARY AND FIRST ALTERNATIVE ANALYSES, YOU ARE SUBSTITUTING ONLY THE COST OF ONE COMPONENT OF BCC'S TOTAL COSTS IN YOUR LCM ANALYSIS. PLEASE EXPLAIN WHY THE COMMISSION SHOULD ACCEPT THIS METHOD.

A. As previously mentioned, the major cost driver of BCC's higher than market cost is the surface operations. The average surface cost of coal for the timeframe is [redacted] as compared to the average underground cost of coal of [redacted]. Although there is a distinct difference between the two costs, my recommendation is an adjustment from ***BCC's weighted costs***. In reviewing data supplied by Idaho Power, surface and underground operations are budgeted (controllable and non-controllable) as separated operations with specific, dedicated costs. As previously mentioned, the underground operations are the primary source of coal being supplied from BCC.

Q. BECAUSE OF THE VARIATION IN BCC SURFACE OPERATIONS COSTS THAT RESULT FROM EITF 04-6, DO YOU BELIEVE THE SURFACE COSTS RELATED TO EITF 04-6 SHOULD BE LEVELIZED OR TREATED

AS A DEFERRAL TO SOFTEN THE ANNUAL VARIATION ON TOTAL COSTS FOR BCC?

A. No. Although EITF 04-06 requires mines to include stripping costs in the cost of coal that is extracted in a given year, the ***ratemaking*** standard for affiliated interest contracts is the LCM pricing policy outlined in OAR 860-027-0048, *Allocation of Costs by an Energy Utility.* As previously noted, PacifiCorp, which is part owner of BCC, claims in UE 207 PPL/201, Lasich/2-3,[16] that the magnitude of the disparity (resulting from EITF 04-6) will fluctuate based on the amount of coal extracted. However, what will not change is the LCM standard that affiliated pricing is determined for ratemaking. The affiliate's cost, no matter how costs are affected by EITF 04-6 (increased or decreased), should always be examined in comparison to market costs. As previously mentioned, other mines contracted by Idaho Power must comply with this accounting requirement; and it is not a unique phenomenon to BCC.

Because the PCAM is an annual filing that includes other changes in power supply costs from year to year, Staff will be able to perform analyses of the affiliated mines' cost and relationship to market on an annual basis. Because BCC's costs will be reviewed in context of the LCM standard on an annual basis, there is no need to levelize these costs or create a regulatory asset balancing account. In any scenario that compares extracted coal to stripped coal, the affiliate's coal costs would still be the starting basis for Staff's recommendation. It is also important to note that customers would only see a

[16] Included in Exhibit Staff/203, pages 20-21.

"benefit" of EITF 04-6 if Idaho Power's costs are lower than market in low cost years.

Q. DID YOU REVIEW SPECIFIC LINE ITEM COSTS FOR BCC?

A. As part of my review, I reviewed the projected 2010 line item costs for BCC. This review resulted in the identification of costs (certain bonus amounts, donations, fine/citations, etc.) that Staff would recommend as adjustments for the parent company (Idaho Power) during a general rate case review. However, as a result of the LCM analyses, I did not make these adjustments, as the LCM analyses resulted in greater adjustments to Bridger costs.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS TO COAL IDAHO POWER'S COAL POWER SUPPLY COSTS.

A. The following table summarizes my recommended adjustments to Idaho Power's coal power supply costs:

Table 7 – Alternative Recommended Oregon Adjustments

Primary Adjustment	$723,110
Alternative Adjustment	$691,354

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

January 20, 2010

WITNESS QUALIFICATION STATEMENT

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

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

<u>REDACTED VERSION</u>
January 20, 2010

STAFF EXHIBIT 202

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 09 - 418. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 214 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

January 20, 2010

ORDER NO. 91-567

ENTERED APR 25 1991

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UI 107

In the Matter of the Application of IDAHO POWER COMPANY for approval of an agreement for coal sales with Bridger Coal Company, a joint venture consisting of Idaho Energy Resources Company, A Wyoming Corporation, and Pacific Minerals, Inc., A Wyoming Corporation.	)	ORDER

DISPOSITION: GRANTED

On January 22, 1991, Idaho Power Company (Idaho) filed an application with the Public Utility Commission pursuant to ORS Chapter 757 and OAR 860-27-040. Idaho requested approval of certain coal sales agreements between Idaho, PacifiCorp dba Pacific Power & Light Company (Pacific), and Bridger Coal Company (Bridger).

At its April 16, 1991, public meeting, the Commission adopted staff's recommendation that the application be granted.

The Commission makes the following:

FINDINGS OF FACT

Jurisdiction

Idaho is an Idaho corporation, duly qualified to transact business in the state of Oregon. Idaho engages in the generation, purchase, transmission, distribution, and sale of electric energy to the public in the state of Oregon. Idaho Energy Resources Co. (IERCO) is a wholly owned subsidiary of Idaho. IERCO was incorporated under the laws of the state of Wyoming. Pacific Minerals, Inc. (PMI), is a wholly owned subsidiary of Pacific, incorporated under the laws of the state of Wyoming. Bridger is a joint venture consisting of IERCO and PMI.

On September 22, 1969, Pacific and Idaho entered into agreements for the ownership, construction, and operation of a 1,500 MW coal-fired electric power plant in Wyoming, known as the Jim Bridger Project. The ownership agreement provided for the joint ownership of certain leases covering coal deposits located near the Jim Bridger plant. The operation agreement contemplated joint operation of these coal properties.

Idaho and Pacific subsequently agreed that the coal properties, rather than being jointly owned and operated by Pacific and Idaho, would be owned and operated pursuant to a joint venture agreement dated February 1, 1974. The joint venture, known as the Bridger Coal Company, consists of IERCO, owning one-third of Bridger, and Pacific, owning two-thirds. Idaho transferred to IERCO all of its right, title, and interest in these coal leases. IERCO, in turn, transferred its interest to Bridger pursuant to the joint venture agreement. On February 1, 1974, Pacific and Idaho entered into a coal sales agreement wherein Pacific and Idaho agreed to purchase, and Bridger Coal agreed to deliver and sell coal from coal properties located near the Jim Bridger plant. Pursuant to an amendment dated December 14, 1973, Pacific and Idaho agreed to the construction of a fourth 500 MW unit at Jim Bridger. On September 1, 1979, the coal sales agreement was amended to increase the total annual tonnage of coal sales to provide coal for the newly constructed unit. Other amendments to the coal sales agreement were entered into by agreements dated March 7, 1988, and by an agreement dated January 1, 1990.

IERCO is a wholly owned subsidiary of Idaho and is an affiliated interest since Idaho and IERCO have four directors and/or officers in common. Bridger is likewise an affiliated interest of Idaho in that one-third of Bridger is owned by IERCO, Idaho's wholly owned subsidiary, and therefore Bridger is an entity, 5 percent or more of which is owned by Idaho pursuant to ORS 757.015(6).

Idaho had previously understood that IERCO and Bridger were not subject to affiliated interest filing requirements under ORS 757.495 and OAR 860-27-040 inasmuch as all of IERCO's transactions with Idaho have been subject to regulatory scrutiny and IERCO is disregarded as a separate entity for rate-making purposes. However, in recent discussions with Commission staff and the Attorney General's office, Idaho was informed that transactions with IERCO are technically subject to affiliated interest filing requirements, notwithstanding the fact that IERCO operations are included with Idaho's operations for purposes of rate making. Idaho desires to comply fully with the spirit and the letter of affiliated interest filing requirements and makes this application to ensure compliance with ORS 757.495 and OAR 860-27-040.

Separate records and accounts for IERCO are maintained and the operations of IERCO as a joint venturer in Bridger are subject to regulatory review and scrutiny together with those of Idaho during general rate cases. The operations of IERCO are summarized in Idaho's semiannual reports of operations filed with the Public Utility Commission. IERCO's results of operations have been merged, consolidated, and included with Idaho's for the purposes of filing of income tax returns and for rate-making purposes. Therefore, there is no danger of cross-subsidization between Idaho and IERCO, nor is there any danger of Idaho paying in excess of market value to IERCO or its assignees for the coal purchased. Idaho is paying for its coal the same as if IERCO were not even involved in this transaction. Further, the coal sales agreements have and will continue to provide a reliable source of low-cost coal for the operation of the Jim Bridger plant.

Idaho believes that the proposed coal sales agreements are of benefit to its customers and permit the coal to be purchased by Idaho at reasonable prices. The coal sales agreements do not impair Idaho's ability to provide its public utility service.

Idaho proposes that the coal sales agreements be approved in their entirety.

OPINION

The following statutes are applicable to this transaction:

ORS 757.005 defines a public utility as, *inter alia*, an entity which owns, operates, manages, or controls all or part of any plant or equipment in this state for the production, transmission, delivery, or furnishing of heat, light, or power, directly or indirectly to the public. Idaho is a public utility subject to the Public Utility Commission's jurisdiction.

ORS 757.015(5) defines an "affiliated interest" as "every corporation which has two or more officers or two or more directors in common with such public utility." Idaho and IERCO have four officers and/or directors in common; therefore, an "affiliated interest" relationship exists. Likewise, ORS 757.015(6) defines an affiliated interest as . . . "Every corporation and person, five percent or more of which is directly or indirectly owned by a public utility." One-third of Bridger is owned by IERCO, Idaho's wholly owned subsidiary. Therefore, an affiliated interest exists between Idaho and Bridger.

ORS 757.495 provides that no public utility shall contract with an affiliated interest for services without the Commission's approval. The statute was designed to protect utility customers from abuses which may arise from less-than-arm's-length transactions. CP National Corporation, UF 3842, Order No. 82-93 at 2; Portland General Electric Company, UF 3739, Order No. 1-737 at 6. The standard of review is whether the proposed contract is ". . . fair and reasonable and not contrary to the public interest . . . ." See ORS 757.495(3).

The application should be granted. The coal sales agreements in question will not harm Idaho's customers because the agreements provide to Idaho a reliable source of low-cost coal for operation of the Jim Bridger plant.

The transfer price for the coal which is provided by Bridger to Idaho shall be billed at actual cost. Cost in this case is equivalent to market for the services. Since all of IERCO's results of operation are merged with and made a part of Idaho's for rate making, there is no possibility of cross-subsidization. The Commission concludes that the agreement is fair and reasonable and not contrary to the public interest.

Idaho's contract with Bridger has and shall continue to be recognized for rate-making purposes. Expenditures made should be charged to accounts in the manner directed by the Federal Energy Regulatory Commission regulations and by the Commission's rules.

CONCLUSIONS OF LAW

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

2. An affiliated interest relationship exists between both Idaho and IERCO and Idaho and Bridger.

3. The coal sales agreements referred to hereinabove and made a part of the applicant's case are fair and reasonable and not contrary to the public interest.

ORDER

IT IS ORDERED that:

1. The application of Idaho Power Company for approval of its coal sales agreements, dated February 1, 1974, between Pacific Minerals, Inc.; Idaho Power Company; and Bridger Coal Company, as amended, by amendments dated December 14, 1973; September 1, 1979; March 7, 1988; and January 1, 1990, is granted. This approval shall be effective for accounting purposes as of January 1, 1991.

2. Idaho shall provide staff access to all books of account, as well as all documents, data, and records of Idaho and Idaho's affiliated interest which pertain to the transactions between Idaho and its affiliated interests, IERCO, and Bridger Coal Company.

ORDER NO. **91-567**

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

4. Idaho Power Company has the responsibility of timely notifying the Commission of all management studies and/or analyses, internal or external audit reports, and any related studies or reports pertaining to the services agreement between Idaho, Pacific, and Bridger and shall promptly provide such information to the Commission upon request.

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

6. Idaho shall comply with the annual reporting requirements for affiliated interest transactions.

Made, entered, and effective APR 25 1991.

PUBLIC UTILITY COMMISSION OF OREGON

Nancy Towslee
Nancy Towslee
Commission Secretary

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

UI107.ORD

ENTERED JUN 12 2001

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UI 189

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

DISPOSITION: APPLICATION APPROVED WITH CONDITIONS

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

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

OPINION

Jurisdiction

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

Affiliation

An affiliated interest relationship exists under ORS 757.015.

Applicable Law

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

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

CONCLUSIONS

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

2. An affiliated interest relationship exists.

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

4. The application should be granted, with conditions.

ORDER

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

Made, entered, and effective ________________________.

BY THE COMMISSION:

____

Vikie Bailey-Goggins
Commission Secretary

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

ITEM NO.__ Staff/203
Dougherty/8

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

REGULAR AGENDA___ CONSENT AGENDA_X_ EFFECTIVE DATE________

DATE: May 16, 2001

TO: Phil Nyegaard through Marc Hellman and Mike Myers

FROM: Tom Riordan

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

SUMMARY RECOMMENDATION:

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

DISCUSSION:

Background:

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

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

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

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

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

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

<u>Issues</u>

I have investigated the following issues:

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

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

<u>Transfer Pricing and Allocation Methods</u> – The Commission's transfer policy for goods and services purchased by a regulated electric utility from an affiliate shall be priced at the lower of cost or fair market rate. This policy likely has been met because BCC is

charging PacifiCorp a price for its coal supply based on BCC's fully distributed cost that is currently less than the market rate. The company's rate of return used in billing from BCC to PacifiCorp is at the same rate authorized by the Commission in PacifiCorp's most recent rate case. This is consistent with the Commission's affiliated interest (AI) transfer pricing policy. Proposed ordering condition No. 4 is included to ensure that PacifiCorp adheres to the Commission's policy.

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

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

CONCLUSIONS:

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

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

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

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

DETAILED RECOMMENDATION:

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

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

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

Q. Please compare Bridger Mine costs relative to other supply options.

A. The Company's fueling strategy was developed to insure low cost, optimum quality, and a secure long-term coal supply for the Company's plants. The Bridger Mine continues to be the optimum long-term coal supply for the Bridger Plant, in combination with the Black Butte Mine agreement. The Southwest Wyoming coal market represents a niche market, with total annual production estimated at only 15 million tons. The Bridger and Naughton Plants consume approximately 11.5 million, or 75 percent of the native production. Most of the remaining local production is consumed by nearby industrial customers. The Company has contracted for all available supplies from the Black Butte Mine. There is no additional capacity in the area to supply the Bridger Plant.

Q. Outside of the Southwest Wyoming area, what options are available to supply the Bridger Plant?

A. Powder River Basin ("PRB") coals are the most feasible market alternative for supplying the Bridger Plant. These supplies are located approximately 560 miles from the plant, so transportation costs are a major cost driver. The Company has periodically evaluated PRB coals relative to the Bridger Mine. Without considering the capital modifications to the unloading facility nor the retrofitting of the generating units to burn PRB coals, PRB coal is still more expensive. Based on the latest Union Pacific rail transportation proposal, the delivered cost of PRB coal is over $5/ton higher than coal from the Bridger Mine in the test period. Thus, coal from the Bridger Mine remains below the costs of any market alternative available to the Company.

that the Coal Supply Agreement is in the public interest under the provisions of ORS §§ 757.490 and 757.495.

6. Annual Bridger Coal Costs and Recording of Costs

The coal supply agreement determines the annual Bridger coal costs as described in Application Section 5 above. Expenditures and coal investments are charged to accounts in the manner directed by the Federal Energy Regulatory Commission regulations and the Commission's rules.

7. Reasons for Procuring Coal from Bridger Coal Company

In 1969, PacifiCorp's predecessor (Pacific Power & Light Company) and Idaho Power Company agreed to construct and operate the Jim Bridger generation plant. The utilities possessed joint ownership of certain leases covering coal deposits acquired from the Union Pacific Railroad, the United States Government and the State of Wyoming located near the generation plant site. The obvious advantage of construction of a generating plant near the plant's fuel source is that fuel transportation and handling costs would be minimized. In addition, Bridger Coal Company coal is of high quality, with BTU content typically ranging from 9200 to 9400 BTU per pound. This is a high BTU content for Wyoming coal. The generation plant facilities were designed to burn the type and quality of coal from these locations. Approximately 70 percent of the Jim Bridger generation plant's coal requirement is obtained from the adjacent mine owned and operated by the Bridger Coal Company.[2]

PacifiCorp's decision to execute the coal supply agreement was tied inextricably to the Company's decision to take advantage of construction of a generating plant near a source of quality fuel.

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[2] Most of the remaining generation plant coal needs are purchased from the Black Butte Coal Company. The Black Butte Mine is located approximately 17 miles from the Jim Bridger generation plant and operates in the same coal seam that is being mined by the Bridger Coal Company. Thus, the two coal supplies are of comparable quality.

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

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

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

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

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

3. Company's Position

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

4. Discussion

The company provided no figures to refute staff's calculation that Bridger Coal's return on investment at the $7.78 sales price would be 18.06 percent, or that its return on common equity would be 36.80 percent. The company acknowledges the Bridger surface mine in design and geology. The new agreement replaces an existing agreement that expires in December 2009. The 2010 price under the new contract is approximately 34 percent higher than the 2008 coal price. This 2010 pricing takes into account lower priced carryover tonnage from the prior contract. Excluding the carryover tonnage, the new contract price increase is over 50 percent.

Q. Please provide an overview of cost increases at the Bridger Mine reflected in this filing.

A. Bridger Mine costs in the 2010 TAM are projected to increase from $29.37/ton in 2008 to $33.54/ton in 2010. The Bridger Mine is located in Southwest Wyoming and operated by the Bridger Coal Company ("BCC"). It consists of two different mining operations: an underground mine and a surface mine. The Bridger Mine is subject to substantially increased taxes and royalty payments in the test period due to higher valuations driven by higher market prices. Higher production taxes and royalties, alone account for approximately $1.70/ton cost increase in 2010, more than 40 percent of the total increase.

Q. How has the Bridger surface mine changed in recent years?

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

Q. Do Bridger surface mine costs in this case also reflect an increase associated with final reclamation charges?

A. Yes. The current filing includes a new contribution charge of $0.84/ton for final reclamation. This reclamation charge reflects the most recent final reclamation study prepared by BCC as well as BCC's trust fund balance as of December 2008. The trust fund is utilized to perform final reclamation and monitoring activities required under the Surface Mine Control and Reclamation Act of 1977. Trust fund earnings in 2007 and 2008 were negatively impacted by the downturn in the economy.

Q. What other specific drivers are causing Bridger Mine costs to increase?

A. Other major contributing factors include:

- Increases in labor costs due to an increase in workforce size and wage and benefit increases,
- Commodity cost escalation,
- Maintenance cost increases as mining equipment is scheduled for rebuilds, component exchanges, etc., and
- Increases in depreciation, depletion and amortization expense of approximately $0.30/ton associated with additional mine infrastructure placed in service in 2010.

OPUC Data Request 51

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

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

Response to OPUC Data Request 51

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

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

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

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

e. See above.

IDAHO POWER®
An IDACORP Company

December 31, 2009

Subject: Docket No. UE 214
Idaho Power Company's Responses to Staff's Data Requests 20-21

<u>STAFF'S DATA REQUEST NO. 20</u>:

As a follow-up to IPC's response to Staff Data Request #1, please explain the third party deferred pricing.

a. Is this price added to the spot price to determine the cost for the associated delivery or is it a stand-alone price per ton?

b. For each month, please provide the total cost and average cost per ton for the third party mine based on tons delivered.

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 20</u>:

a. The line item entitled "Black Butte Mine – Deferred / Force Majeure" represents the contract price of $11.07 per ton for coal to be delivered in 2010 from the Black Butte mine (stand-alone price per ton). The tonnage to be delivered in 2010 was deferred or delayed from prior years, either because of decreased coal requirements at the Jim Bridger Plant or force majeure events. This is the total cost per ton, FOB mine.

b. Please see the attached Excel spreadsheet.

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.

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support
Of Opening Testimony

<u>REDACTED VERSION</u>
January 20, 2010

STAFF EXHIBIT 204

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 09 - 418. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 214 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

UE 214
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CERTIFICATE OF SERVICE

UE 214

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

Dated at Salem, Oregon, this 20th day of January, 2010.

Kay Barnes

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Public Utility Commission
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