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March 17, 2010

Via Electronic Filing and U.S. Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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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 Reply 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))

CERTIFICATE OF SERVICE

UE 214
REPLY TESTIMONY

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 17th day of March, 2010.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
550 Capitol St NE Ste 215
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UE 214
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PUBLIC UTILITY COMMISSION OF OREGON

UE 214

STAFF REPLY TESTIMONY OF

ED DURRENBERGER
MIKE DOUGHERTY

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

REDACTED VERSION
March 17, 2010

CASE: UE 214
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 300

Reply Testimony

March 17, 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. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS DOCKET?

A. Yes, I provided opening testimony about the October update portion of the 2010 Annual Power Cost Update (APCU) filed by Idaho Power Company (Idaho Power or company) docketed as UE 214.

Q. DID YOU PREPARE AN EXHIBIT FOR YOUR REPLY TESTIMONY?

A. No.

Q. HOW IS YOUR REPLY TESTIMONY ORGANIZED?

A. In my opening testimony I discussed concerns I had with some of the inputs to the power cost modeling used to derive the October update of base power supply expenses for the power cost year of April 2010 through March 2011. Since that time parties have convened a workshop and settlement meeting and I learned more about the Idaho Power initial filing of the October update.

Q. HAS WHAT YOU LEARNED CHANGED YOUR RECOMMENDED ADJUSTMENTS FOR THE COMPANY'S ORIGINAL FILING OF THE OCTOBER UPDATE?

A. To some extent yes. I had originally proposed that the following categories of inputs be adjusted in various ways:

- Load growth: the modeled sales to customers used as the starting point on which the power cost is modeled. The Hoku power contract: this is a new high load industrial contract that was modeled as being in place for the entire power cost year.
- PURPA power purchases: a number of PURPA power purchase agreements were modeled into the October update of the power cost dispatch model for projects whose start-up date was not certain.
- Salmon Flow Augmentation: a change in the water release regiment intended to augment salmon migration in the spring led to a modeling change that then resulted in a change to the timing of normal hydro generation. The company also made another small adjustment for declining reach, resulting in less overall hydro generation than normal.
- Water rights lease agreement: the costs and benefits for a new water rights lease agreement were not included in the base rate update.

Since these issues are all inputs to the power cost model, and the model output is what generates the update to base power costs that comprise both the October update and the March forecast parts of the "Annual Power Cost Update", it is difficult to come up with an exact dollar value of each adjustment that I propose. Each input change can have an effect on the value of each of the other inputs and the value of each individually may not be the same as the value of all the changed combined. As such, I will explain the nature of my issues, and the reasons for any changes to model inputs I propose. When a decision is made on these and other cost and load input changes that other parties may have proposed, Idaho Power will be asked to make the necessary modeling input changes and run the power cost model to then generate a new annual power supply October update.

Q. WHAT DO YOU NOW PROPOSE REGARDING THE ISSUES YOU RAISED IN OPENING TESTIMONY?

A. For the first issue, I accept the load forecast that the company used in its original October update filing. Idaho Power has been able to demonstrate that the load forecast that was used was made in a manner consistent with the load growth forecasts used in their most recent Integrated Resource Plan (IRP) Docket LC50. Other utilities with filings before the Commission have been reporting small declines in sales to customers in Oregon in the coming year, and despite the fact that the Idaho Power IRP, containing a similar load growth for the power cost period, has not yet been fully vetted or acknowledged by the Oregon Commission, I am persuaded that the load forecast that was used is reasonable. At 1,817 average megawatts (aMW), the forecast load is essentially the same as the load that was forecast in 2008 (1,825 aMW). The load number I had proposed in my opening testimony, 1,797 aMW, was the calendar year (CY) 2010 IRP forecast load from the LC 50 work papers. The load period in question, however, is the April 2010 through March 2011 period, a later period than the IRP calendar year. Interpolating the load forecasts for the nine months in 2010 and three months in 2011 results in the load figure proposed by Idaho Power in this case.

Q. DO YOU WISH TO SAY ANYTHING MORE ABOUT THE LOAD FORECAST?

A. Yes, although I have acknowledged that the 1,817 aMW load figure was determined using appropriate IRP methodologies, I continue to support an adjustment for the Hoku industrial load which reduces the modeled load by the amount modeled in the special Hoku sales and service contract. Should circumstances change with Hoku when it commences operations, the methodology approved in Order No. 08-238 allows loads to be adjusted as necessary during the proceeding.

Q. PLEASE ELABORATE ON THE HOKU ADJUSTMENT YOU PROPOSED IN YOUR OPENING TESTIMONY.

A. In my opening testimony I proposed that both the power sales and revenue for the Hoku industrial sales contract be removed from the initial model inputs. The reasoning behind this was that the Hoku factory was still under construction. There is considerable uncertainty as to when the plant will start production and thereby begin taking the large industrial load the service agreement indicated. A recent review of the Hoku web site indicates that, as of early March of 2010, the final financing had been secured to continue design, procurement and construction of the Pocatello Idaho polysilicon manufacturing facility. I propose that the Hoku new industrial load and revenue is not known and measurable and should not be modeled in the 2010 APCU at this time. In my opening testimony I mistakenly assumed that the Hoku load contained in the Aurora power cost model included only first block loads which I estimated to be approximately 39 aMW. I have since learned from the Idaho Power, in response to Staff Data Request 19, that the modeled load was pulled directly from the electric service agreement and that the revenue contained in the October update includes demand and load costs pursuant to that agreement. I therefore wish to clarify my intent. The entire Hoku service agreement load and revenue included in the model should be removed from the October update and from the March forecast loads as well in the 2010 APCU.

Q. WHAT IS THE ISSUE WITH PURPA QUALIFYING FACILITY CONTRACTS INCLUDED IN THE POWER COST MODELING FOR THE OCTOBER UPDATE OF BASE POWER COSTS?

A. There are a number of PURPA power purchase agreements that Idaho Power has signed with counterparties that have not yet resulted in the supply of energy to the Idaho Power system. Opening testimony discusses this point. *See* Staff/100, Durrenberger/5-7. Basically the company's recent history in regard to PURPA QF contracts is that a large number of PURPA QF contracts get signed for start up the next year and then there is a large decrease in actual PURPA QF power and costs the next year because some of the projects never actually went in to operation. It is not possible to know which of the projects expected to start in the post June 2010-2011 period will fail to come on line. I propose that the Commission not include the energy or costs for any PURPA QF projects that have not actually started up by the time these power cost updates are finalized. These avoided cost based contract costs should replicate approximately what the company would be paying for comparable energy. Also, as I had stated in opening testimony, I agree with the company being allowed to revise some PURPA pricing to correct an error noted by the company in its opening testimony.

Q. WHAT IS YOUR NEXT ISSUE?

A. Idaho Power made an adjustment to modeled normalized hydro generation due to a shifting of the timing of water release in the Snake River basin above Brownlee reservoir. This resulted in a modeled larger than “normal” amount of hydro generation in May and June and a corresponding lower amount of hydro generation in July and August. The US Bureau of Reclamation, in its Biological Assessment (BA) of the operations of the Snake River basin, has recently required that the additional water flow for salmon augmentation be shifted from the summer (July-August) to the spring (May-June). Overall, the annual hydro output of the Snake River basin generation system appears unaffected but the shifting of the timing of flow augmentation results in less hydro generation in the high power cost summer months and more generation in the lower cost spring, thereby causing an increase to power costs.

Q. IN OPENING TESTIMONY YOU TOOK ISSUE WITH THIS SALMON FLOW AUGMENTATION ADJUSTMENT. DO YOU NOW WANT TO AMEND YOUR RECOMMENDATION?

A. Yes, I now have seen sufficient evidence from a number of sources to support Idaho Power's position that it does not have any alternative but to comply with the government-mandated change in Snake River flow regimes. I further have gained insight into how the company made the modeling changes and I am more comfortable with the expected system hydro output during the spring and summer months.

Q. DOES THIS MEAN YOU AGREE WITH THE CHANGE TO NORMALIZED HYDRO GENERATION IN THE FILING?

A. Yes and no. I agree that the flow augmentation is required and I agree that hydro generation that previously would have occurred in July and August is now going to shift to May and June. I also agree that the amounts and timing of the generation appear to be modeled correctly in terms of matching the generation in May and June with what had been regularly occurring in July and August.

However, I disagree that it is appropriate for Idaho Power to make this type of stepwise adjustment in normalized generation in the midst of its APCU filing. As I stated in my opening testimony, the company also included a small adjustment to overall hydro output due to what was called a long term decrease in tributary flows to the Snake River Basin. *See* Staff/100, Durrenberger/8. This additional adjustment to normalized hydro generation appeared diminishingly small but, again, should not be part of changes for the APCU filing. I propose to that these power supply changes be allowed in this docket, contrary to my earlier testimony, but request the Commission to require that Idaho Power model changes such as this in a separate filing and docket. In this manner, parties could review the proposed changes and their effects and, if they so choose, offer comments before the changes are implemented in the APCU. I realize the process I propose may seem burdensome; however, the APCU, as envisioned in Order No. 08-238 is a narrowly focused proceeding intended to be less contentious than a general rate case. Because only a limited number of changes or updates are allowed to the inputs in the power cost modeling used to derive the final power supply expenses, the docket typically proceeds relatively quickly. Should parties need to regularly investigate modeling and methodological changes such as were included this time, it may not be possible to resolve all the issues and reach a decision on power costs in time for the June 1 implementation date.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON THIS ISSUE.

A. I agree that the changes to normalized hydro generation that the company made in this APCU are acceptable. I would not favor having any methodological or modeling updates be a part of any future routine APCU power supply expense filings unless the parties have had the opportunity to review the proposed changes and comment on them prior to their use in the power cost update.

Q. ARE THERE ANY OTHER ISSUES THAT YOU WISH TO DISCUSS?

A. Yes, I have one other item that is important to be included in the October update to the APCU. Idaho Power has recently leased some water rights that it can use to release water from the American Falls reservoir in August and September. The company did not include this lease in the 2010 APCU. The cost and modeled benefits from this lease need to be included in the October update in the 2010 APCU. The inclusion of this water lease agreement does not appear controversial from the standpoint of including the costs and benefits in the base power supply October update and the benefits are modeled to exceed the costs.

Q. ARE THERE ANY OTHER ISSUES THAT YOU WISH TO DISCUSS?

A. No, these are all the issues I wish to discuss. Although I have not quantified the rate consequence of the model inputs I have proposed, the Idaho Power APCU is a proceeding whereby parties debate and settle on changes to the Aurora power cost model input and then use the model output to generate the power supply expenses used to determine the APCU. There is ample time between now and the final filing of the power cost update in this docket for the company to make the revisions necessary to the inputs and make a new revised October update model run.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Reply Testimony

March 17, 2010

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

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REPLY TESTIMONY?

A. I include and analyze updated information obtained since I filed my Opening Testimony. I continue to support my adjustment to Bridger power supply costs as previously stated in Staff/200.

Q. HAVE YOU PREPARED ANY EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared:

Exhibit Staff/401, consisting of 21 pages; and

Confidential Exhibit Staff/402, consisting of five pages.

Q. PLEASE PROVIDE A SUMMARY OF YOUR ADJUSTMENTS.

A. The following table summarizes my adjustment to Idaho Power's power supply costs concerning Bridger as listed in Idaho Power/101, Wright/1.

Table 1 –Staff's Adjustment to Bridger

Plant	Exhibit Idaho Power/101, Wright/1	Staff	Adjustment
Bridger	$105,249,100	$89,664,839	$15,584,261
Total Adjustment			$15,584,261
Total Oregon Adjustment (.0464 allocation)			**$723,110**

Q. PLEASE SUMMARIZE THE ANALYSES SUPPORTING YOUR RECOMMENDED ADJUSTMENT.

A. Because Bridger receives coal from an affiliated interest coal mine (Bridger Coal Company (BCC)), 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.

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

A. Yes. As explained in Staff/200, I performed four LCM analyses concerning coal costs from BCC supplied to Bridger. My primary analysis 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. The following table lists the primary and alternate recommendations.

Table 2 –Recommended Oregon Adjustments

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

As previously mentioned in Staff/200, I did not include the second and third LCM analyses as recommended adjustments concerning Bridger power cost supply expense.

Q. IN STAFF/200, DOUGHERTY/6-7, YOU ASSERT THERE IS A MARKET AND AVAILABILITY OF COAL IN THE GREEN RIVER BASIN (GRB). IS THIS STILL YOUR POSITION?

A. Yes. As previously mentioned in Staff/200, Dougherty/6, there is a market and availability of coal in the GRB. Evidence to this fact is:

- Idaho Power uses GRB market supplied coal for approximately one-third of the coal utilized by Bridger;
- As demonstrated in Staff/200, the price of third-party (Black Butte) coal supplied to Bridger is lower than the weighted cost of BCC coal for the time period, April 2010 to March 2011, used in this filing;
- Black Butte is also a surface operation mining operation and is of comparable quality to BCC surface coal;[1]
- There are no physical limitations at Bridger that would prevent additional deliveries of coal from a third party source;[2]

[1] Please see Idaho Power's response to Staff Data Request No. 26. Included in Exhibit Staff 401.
[2] Please see Idaho Power's responses to Staff Data Requests Nos. 35 and 37. Included in Exhibit Staff 401.

- As previously mentioned in Staff/200, Dougherty/7, Commission Order No. 79-754, page 17, refers to PacifiCorp's position on third-party availability in the GRB.[3] It is important to note that although the order is 31 years old, Black Butte and BCC were the only coal mines in Sweetwater County producing any considerable tonnage in 1979, 1980, and 1981. As a result, the dynamics of the market have not significantly changed since the 1979 order;[4]
- Black Butte has previously increased deliveries to Bridger when requested by Idaho Power and PacifiCorp;[5] and
- Idaho Power has confirmed that there have been periods where additional coal has been available in the GRB.[6] Although this available coal will not completely replace the total surface tonnage produced by BCC, it is adequate to fulfill Idaho Power's share of surface tonnage.

To further highlight the potential availability of less expensive coal to replace BCC surface coal, in UE 207 Staff/200, Dougherty/17-19, I performed a LCM analysis that substituted Wyoming Powder River Basin (PRB) coal, including the cost of transportation for BCC's surface coal.[7] This analysis was performed to determine if using PRB coal to replace BCC surface coal would result in lower costs to customers. The answer was yes, because the substitution resulted in an $11 million system reduction to PacifiCorp's Coal

[3] Included in Exhibit Staff 401.
[4] Wyoming Coal Operations Reports (1979, 1980, and 1981) are included in Exhibit Staff 401.
[5] Please see Idaho Power's response to Staff Data Request No. 30 included in Exhibit Staff 401.
[6] Please see Idaho Power's confidential response to Staff Data Request No. 29 included in Confidential Exhibit Staff 402, Dougherty/1.
[7] Included in Exhibit Staff 401.

Fuel Burn Expense. Because Idaho Power receives one-third of BCC's coal, a proportional adjustment (i.e., reduction) to Idaho Power's Bridger power supply cost using PRB coal, including transportation costs as a substitution for BCC surface coal would lower power supply costs by approximately $5.5 million ($255,200 – Oregon).[8] As Idaho Power's response to Staff Data Request No. 43 demonstrates, there have been times in which the Bridger plant received coal shipments from mines in the PRB.[9]

Q. IS IT YOUR POSITION THAT IDAHO POWER MUST BUY THIS AVAILABLE COAL AND NOT USE ITS SURFACE MINING OPERATION?

A. No, not at all. My position is that BCC coal costs in rates must be the ***lower of cost or market***. As previously mentioned:

- BCC is an affiliate of Idaho Power;
- OAR 860-027-0048, *Allocation of Costs by an Energy Utility*, applies to the transfer pricing between BCC and Idaho Power;
- BCC weighted cost per ton is higher than the third party delivered cost per ton.

As a result, the LCM pricing of coal must apply to BCC.

Q. PLEASE PROVIDE A REVIEW OF 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

[8] A cite to the confidential PacifiCorp exhibit is not included at this time as staff counsel is attempting to work through the confidentiality issues associated with using confidential material supplied by a non-party.
[9] Included in Exhibit Staff 401. Please note that the last shipment from the PRB occurred in 2000.

transportation) for each month April 2010 to March 2011. I used the average cost to allow customers to achieve the benefits of the deferred coal. 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. As previously mentioned, Black Butte coal is an excellent market proxy for BCC's surface operations because:

- 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. 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. 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 there is a market and availability of coal in the GRB;

2. The recommendation uses the April 2010 through March 2011 average 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 PROVIDE A REVIEW OF YOUR FIRST ALTERNATE MARKET ANALYSIS.

A. In my first alternate analysis, I followed the same process as the primary market analysis except that I replaced the BCC surface operations with Black Butte's spot and transportation costs. This analysis did not utilize the less expensive deferred price. Because the less expensive deferred coal was not used in the first alternate market analysis to reflect the carry-over tonnage, this first alternate recommended Bridger power supply cost adjustment of $14,899,869 is lower than the primary recommended adjustment. Using Idaho Power's Oregon allocation of 0.0464, the Oregon allocated adjustment is $691,354. I used this as an alternate and not primary adjustment because customers should receive the benefits of the lower cost of deferred coal.

Q. DOES IDAHO POWER ADDRESS THE DECREMENTAL COST OF BCC'S SURFACE PRODUCTION?

A. Yes. In Idaho Power's response to Staff Data Request No. 39, the Company states (emphasis added by Idaho Power):

> A comparison solely of Bridger Coal surface operating costs to other surface operations in southwest Wyoming is spurious. Unlike the Black Butte or Kemmerer mines, Bridger Coal is an integrated mining operation rather than separate surface and underground mines. Every mine, surface and underground, has a unique cost structure. Differences in mining methods, stripping ratios, coal extraction, and mine capitalization all affect the cost structure. Similarly to the Bridger mine surface operation, stripping ratios tend to increase over a mine's life.

> Though, the Bridger mine's stripping ratio is now higher than Black Butte's or Kemmerer's, *the decremental cost of Bridger Coal surface production is less than the cost of other supply options for the Bridger Plant*. Bridger Coal has already mined the lowest stripping ratio reserves – it still, however, remains the least cost supply for the Bridger Plant and Idaho Power Company ratepayers.[10]

In Confidential Exhibit Staff/402, Dougherty/3, I applied 2009 surface allocations to the 2009 underground costs.[11] Although, Idaho Power is correct concerning the decremental costs of the surface operations reducing the costs of the underground operations, the fact is that BCC's weighted cost for the time period of April 2010 to March 2011, is higher than the comparable market coal, Black Butte. Because Black Butte's cost is lower than BCC's weighted cost; is a comparable quality to BCC surface coal; and is available to burn at Bridger, BCC coal is ***not*** the least cost supply to Bridger and Idaho Power customers during the time period of this filing. OAR 860-027-0048 requires pricing from an affiliate to be the lower of cost or market; and market cost, for the stated time period, is lower than BCC's costs.

Q. IS IT STILL YOUR POSITION THAT THE SURFACE COSTS RELATED TO EITF 04-6 SHOULD NOT BE LEVELIZED OR TREATED AS A DEFERRAL TO SOFTEN THE ANNUAL VARIATION ON TOTAL COSTS FOR BCC?

A. Yes. 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

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[10] Included in Exhibit Staff 401.

[11] Included in Confidential Exhibit Staff 402, Dougherty/2-3 and Confidential Exhibit Staff 402, Dougherty/4, Analysis 1. In Analysis 1, I added the overhead costs allocated to the surface mine to the total costs of the underground mine resulting in a higher underground costs for 2009. It should be noted that the amount of underground tons have increased since 2009; and underground costs have subsequently decreased.

interest contracts is the LCM pricing policy outlined in OAR 860-027-0048, *Allocation of Costs by an Energy Utility.* 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. 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 important to note that for the years 2005 through 2009, BCC's average cost per ton has been higher than Black Butte's average cost per ton.[12] As a result, there does not appear to be a recent pattern where the affiliate's costs were lower than market costs.

When comparing surface production costs per ton of BCC to the surface sales price per ton of Black Butte for the same time period, BCC production costs have been lower than Black Butte costs for two of the five years.[13] However it is important to note that the costs reflected are the production costs and not the sales price. According to Idaho Power's response to Staff Data Request No.33:

> The BCC sales price per ton includes an operating margin, equal to the overall rate of return authorized in general rate cases where IERCO/BBC operations are treated as part of the regulated activities of the Company. The sales price is adjusted

[12] Idaho Power's confidential response to Staff Data Request No. 25 included in Confidential Exhibit Staff 402, Dougherty/5.
[13] Included in Confidential Exhibit Staff 402, Dougherty/4, Analysis 2.

> periodically as updated BCC mining expense data becomes available.[14]

As a result, the actual sales price would likely be higher than the production costs, mitigating any cost savings between BCC surface costs and Black Butte costs in the years BCC surface production costs were lower. As previously mentioned, Idaho Power earns a return on its investment and operations at BCC; and as a result, may have incentives to continue operating the captive mine even if costs are higher than market. Additionally, surface mine production tons have decreased significantly over the past few years. Idaho Power appears to refer to the cost effect of the decreased surface production in its response to Staff Data Request No. 39 by pointing out that BCC has already mined its lowest stripping ratio reserves.[15]

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 3 – Recommended Oregon Adjustments

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

Q. DOES THIS CONCLUDE YOUR REPLY TESTIMONY?

A. Yes.

[14] Included in Exhibit Staff 401.
[15] Included in Exhibit Staff 401.

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Exhibits in Support
Of Reply Testimony

March 17, 2010

STAFF'S DATA REQUEST NO. 26:

Please explain the purpose of "mixing" BCC surface and underground coal to achieve required quality levels.

- **a. What are the quality metrics that are being achieved (i.e., Btu, SO_2, other).**
- **b. How is "mixing" performed during the months that BCC does not provide surface coal?**
- **c. Is the BB coal used for "mixing"? Please explain.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 26:

All three coal sources for the Jim Bridger Plant (Bridger surface, Bridger underground and Black Butte) have quality cycles. Geology and quality can vary within a seam as well as from seam to seam. Through blending of coals, both the Bridger Mine and the Jim Bridger Plant minimize quality variations that undermine optimal plant performance. Both the Bridger Mine and the Jim Bridger Plant have installed coal analyzers that provide operations with instantaneous data. With this information, both the mine and the plant can adapt their blending.

The CoalScan Analyzers located at the Bridger Mine measure ash content. The ash content of the underground operation fluctuates depending upon the ash content of the mined seam and the amount of coal produced by the continuous miners. In 2010, for instance, the ash content of the underground coal is projected to range from approximately 10 percent to 22 percent. Comparatively, the ash content of the surface operation is projected to be from 7 percent to 13 percent.

In addition to ash, the Bridger Mine has established coal quality targets for heat content (Btu/lb), ash softening temperature, iron, sodium, and calcium with sodium, ash, and heat content as the most critical variables. From a coal quality perspective, the Bridger surface and underground operations are complementary. On average, the Bridger surface operation produces the coal with the highest sodium, and lowest ash content and ash softening temperatures, while the Bridger underground operation produces the coal with the lowest sodium, and highest ash content and ash fusion temperatures. Fueling plans are prepared to ensure Bridger Mine coal deliveries, in aggregate, conform to established targets.

The Jim Bridger Plant also performs limited blending. To maximize generating availability, a Thermo Fischer CQM Elemental Analyzer has been installed at the Jim Bridger Plant. This analyzer provides the Plant with instantaneous coal quality data as coal is transferred from the stockpile to the coal silos. The plant operator is provided with measurements of moisture, ash, sulfur, heat content, ash softening temperature, iron, calcium, and sodium.

a. Coal quality targets have been established for heat content (Btu/lb), ash content, sulfur, ash softening temperature, sodium, calcium, and iron for Bridger Coal Company, Black Butte Coal Company, and the Jim Bridger Plant. Personnel from the PacifiCorp Fuels Department, Bridger Mine, Idaho Power, and Jim Bridger Plant all participate in daily calls. Fueling plans are jointly reviewed by the participants. Due to Bridger Plant's limited ability to stockpile and blend coal, the Bridger Mine must adapt to the plant's requirements. Depending upon Black Butte's coal content, the Bridger Mine will adjust the proportion of surface and underground deliveries to ensure coal, in aggregate, conforms to established targets.

Coal Quality Targets

	Bridger Coal Company	Black Butte Coal	Jim Bridger Plant
Btu Content	> 9200	> 9000	> 9200
Ash	12% - 14%	11.50%	12%
Sulfur	0.60%	0.60%	0.60%
Ash softening Tempeature	> 2175		> 2175
Sodium	2% - 3%	< 4%	< 3.2%
Calcium	< 8%		< 8%
Iron	< 6%		< 6%

b. Coal deliveries from the Bridger surface operation are projected in all but three months of the test period. During the three months of non-surface deliveries, the Bridger Mine can assure a consistent coal quality by blending stockpiled underground coal. Bridger Mine has stockpiled limited amounts of underground coal with varying quality in three locations. The largest stockpile of underground coal is contained in the stacking tubes located outside the underground portal.

c. Black Butte coal is blended with Bridger Mine coal at the Jim Bridger Plant. Under the prior Black Butte coal supply agreement, in addition to their deliveries by rail, Black Butte Coal Company sourced the Jim Bridger Plant with 750 k tons of premium low sodium, high ash fusion temperature coal from Pits 22, 23 and 24 (Leucite Hills Mine). This coal was transported by truck and stockpiled by Black Butte at a site adjacent to the Bridger Plant. Bridger Plant personnel utilized this coal for blending on an as needed basis. These ultra-low sodium reserves, however, were depleted in 2009.

Under the new Black Butte agreement, with the term of 2010 though 2014, the coal is being sourced from the higher sodium Pit 11 and Pit 14. The current contract specification allows Black Butte Coal Company to ship coal with up to 4 percent sodium on a monthly basis. Sodium content above 3.2 percent causes ash to slag on the boiler tubes. Blending with lower sodium Bridger Mine coal is required to mitigate Black Butte coal deliveries with sodium content above 3 percent.

STAFF'S DATA REQUEST NO. 35:

What are the physical limitations, in both qualitative and quantitative terms, of the maximum amount of tonnage regarding delivery of BB coal if higher delivery amounts were needed? Please explain.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 35:

Absent any modifications to the Bridger plant unloading facility, the Bridger plant could unload approximately 3.7 million tons of Black Butte coal shipped by rail annually.

March 11, 2010

Subject: Docket No. UE 214
Idaho Power Company's Responses to Staff's Data Requests 37-43

STAFF'S DATA REQUEST NO. 37:

As a follow-up to Staff Data Requests Nos. 34 and 35:

a. How is BCC coal delivered to Bridger?

b. Is the same material handling system (MHS) used to unload coal from both BB and BCC? Please explain.

c. If a different MHS is used for the two sources, please explain these differences. Please explain and provide the unloading rate and capacity (i.e., tons per hour, railcar per hour, etc.) of each MHS.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 37:

a. The delivery of coal to the Bridger plant from the Bridger Coal mine is achieved by utilizing a conveyor system. The Bridger Coal conveyor system is rated at 1,800 tons/hour and has a total system length of approximately 48,000 feet.

b. The coal delivered from Bridger Coal enters a plant transfer station (BCCTS) and from there flows to a common stackout system that feeds the radial stacker stockpile area and a fixed stockpile area. The coal delivered from the Black Butte mine is delivered via a rail unloading facility to a sub-surface conveyor system that then delivers the coal to a different transfer station ("BBTS") which is adjacent to the BCCTS. The coal from the BBTS is then fed to the same common stackout system as the coal from Bridger Coal.

c. The coal delivery systems are different in that the BCCTS can only deliver up to 1,800 tons/hour to the common stackout system. The rail unloading conveyor system can deliver up to 2,200 tons/hour to the common stackout system from the BBTS. Approximately 20 railcars/hour can be unloaded at the 2,200 tons/hour rate.

If there is sufficient available capacity on the stockpiles, both transfer stations can be operated at the same time at the maximum rates. Stockpile capacity, equipment availability, and blending needs (coal quality) can constrain the maximum delivery rates.

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. See Pacific N. W. Bell v. Sabin, 21 Or. App. 222, 534 P.2d. 984 (1975), rev. denied.

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 equity return rate 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 Sabin 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

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COAL SUMMARY OF MINING MANHOURS, ACCIDENTS, FREQUENCY & SEVERITY RATES 1979

Name of Operator or Company	Manhours Underground	Manhours Surface	Frequency Under-ground	Frequency Surface	Severity Under-ground	Severity Surface	Underground Fatal	Underground Nonfatal	Surface Fatal	Surface Nonfatal	No. of Under-ground Employees	Total No. of Employees
Rosebud Coal Sales Co. Rosebud Mine		415,305		.96		311.57			0	2		243
Stansbury Coal Company Stansbury Mine	272,735	87,600	5.13	2.28	4719.59	18.26	1	7	0	1	115	155
Thunder Basin Coal Company Black Thunder Mine		534,906		1.86		22.43			0	5		332
*Contractor's data (TOTAL)		136,988		1.45		7.29			0	1		205
Wyodak Resources Devel. Corp. Wyodak Mine		104,061		3.84		136.45			0	2		49
*Contractor's data		18,276		0.00		00.00			0	0		18
University of California Lawrence Livermore Lab. Hoe Creek Gasification Site		36,432		10.97		76.85			0	2		60
TOTALS:	677,659	10,944,814	5.13	2.43	2,256.16	41.71	2	18	0	133	350	5,265 operator 957 contractc 6,222 Total Co Industr

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COAL OPERATIONS - 1979

Name & Address of Operators	Name of Mine & Mgr. or Supt.	County & Location	Facilities Operated	No. of Employees	1979 Production
AMAX Coal Co. P.O. Box 3005 Gillette, WY 82716	Belle Ayr Mine Harold Bailey	Campbell	Open Pit Coal Mine	412	14,996,875
AMAX Coal Co. P.O. Box 3005 Gillette, WY 82716	Eagle Butte Mine Fred VonKaenel	Campbell	Open Pit Coal Mine	156	3,732,66
Arch Mineral Corporation P.O. Box 490 Hanna, WY 82327	Seminoe Mine #1 Darrel Synder	Carbon	Open Pit Coal Mine	235	2,284,66
Arch Mineral Corporation P.O. Box 530 Hanna, WY 82327	Seminoe Mine #2 D.H. Kieper	Carbon	Open Pit Coal	325	2,719,79
Ash Creek Mining Company P.O. Box 6528 Sheridan, WY 82801	PSO Mine #1 Paul Jones	Sheridan	Open Pit Coal	2	
Atlantic Richfield P.O. Box 1839 Gillette, WY 82716	Coal Creek Mine G.E. Calahan	Campbell	Open Pit under construction	12	
B.E.C.O.R. P.O. Box 643 Thermopolis, WY 82443	Roncco Mine William B. Leppala	Hot Springs	Underground coal mine and crushing and screening plant	13	14
Big Horn Coal Company P.O. Box 724 Sheridan, WY 82801	Big Horn Coal W.M. Rosewarne	Sheridan	Open Pit Coal Mine	302	3,523,7

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COAL OPERATIONS CONTINUED 1979

Name & Address of Operators	Name of Mine & Mgr. or Supt.	County & Location	Facilities Operated	No. of Employees	1978 Production
Black Butte Coal Company P.O. Box 98 Point of Rocks, WY 82942	Black Butte Coal Jim Wilson	Sweetwater	Open Pit Coal Mine	485	1,200,00C
Black Mountain Coal Company P.O. Box 871 Sheridan, WY 82801	Black Mountain Ron Spahn	Sheridan	Open Pit Coal (FINAL REPORT)	7	8,217
Bridger Coal Company P.O. Box 2068 Rock Springs, WY 82901	Jim Bridger Mine Glenn A. Goss	Sweetwater	Open Pit Coal	331	5,690,41·
Carbon County Coal Company P.O. Box 370 Hanna, WY 82327	Carbon #1 Mine Alex Sanders	Carbon	Underground Coal Mine	94	96,26[illegible]
The Carter Mining Company P.O. Box 3007 Gillette, WY 82716	Caballo Mine J.D. Goodrich	Campbell	Open Pit Coal Mine	34	1,272,96[illegible]
The Carter Mining Company P.O. Box 204 Gillette, WY 82716	Rawhide Mine P.W. Erickson	Campbell	Open Pit Coal Mine	219	3,593,41[illegible]
Cordero Mining Company P.O. Box 1449 Gillette, WY 82716	Cordero Mine Lowell B. Page	Campbell	Open Pit Coal Mine	112	3,832,80C
Delzer Construction Co., Inc. P.O. Box 2737 Gillette, WY 82716	Fort Union Coal Mine Stuart R. Felde	Campbell	Open Pit under construction	34	7,737

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COAL OPERATIONS CONTINUED

Name & Address of Operators	Name of Mine & Mgr. or Supt.	County & Location	Facilities Operated	No. of Employees	1979 Production
Energy Development Company P.O. Box 600 Hanna, WY 82327	Vanguard No. 2 Mine Edward F. Ziolkowski	Carbon	Undergound Coal Mine	233	345,274
F.M.C. Corporation, Natural Resources Div. P.O. Box 750 Kemmerer, WY 83101	Skull Point Mine John V. Corra	Lincoln	Open Pit Coal	94	813,34E
Glenrock Coal Company P.O. Box 159 Glenrock, WY 82637	Dave Johnston Mine Larry Tabaka	Converse	Open Pit Coal	155	3,828,162
The Kemmerer Coal Company Frontier, WY 83121	Elkol Surface Mine James R. Brophy Jr.	Lincoln	Open Pit Coal	244	1,778,85E
The Kemmerer Coal Company Frontier, WY 83121	Sorensen Surface James R. Brophy Jr.	Lincoln	Open Pit Coal	314	2,502,267
Kerr-McGee Coal Corporation Caller Box 3013 Gillette, WY 82716	Jacobs Ranch Mine Donald R. Sheets	Campbell	Open Pit Coal	197	4,681,24[illegible]
Kerr-McGee Coal Corporation Caller Box 3014 Gillette, Wyoming 82716	Clovis Point Mine S.J. Larsen	Campbell	Open Pit Coal	115	293,484
Medicine Bow Coal Company P.O. Box 550 Hanna, WY 82327	Medicine Bow Mine Harold Combs	Carbon	Open Pit Coal	231	2,345,917

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COAL OPERATIONS CONTINUED 1979

Name & Address of Operators	Name of Mine & Mgr. or Supt.	County & Location	Facilities Operated	No. of Employees	1979 Production
Northwestern Resources Co P.O. Box 729 Thermopolis, WY 82443	Grass Creek Mine Monte J. Steffan	Hot Springs	Open Pit Coal	4	9,206
Prospect Point Coal Company P.O. Box 8 Point of Rocks, WY 82942	Prospect Point George Herne	Sweetwater	Coal Stockpile, Loadout	10	—
Resource Exploration & Mining, Inc. P.O. Box 750 Hanna, WY 82327	Rimrock 1 and 2 Delmar Rames, V.P. Tom Bennett, Supt.	Carbon	Open Pit Coal	56	596,044
Rosebud Coal Sales Company P.O. Box 780 Hanna, WY 82327	Rosebud Mine Tom Hornbeck	Carbon	Open Pit Coal	243	2,396,358
Stansbury Coal Company P.O. Box 2088 Rock Springs, WY 82901	Stansbury Mine A.J. Christenson	Sweetwater	Underground Coal Mine	155	287,124
Thunder Basin Coal Company P.O. Box 406 Wright, WY 82732	Black Thunder Mine C.B. Smith	Campbell	Open Pit Coal	332	6,244,164
Wyodak Resources Development Corporation Garner Lake Route Gillette, WY 82716	Wyodak Mine W.J. Westre	Campbell	Open Pit Coal	49	2,364,000

COAL OPERATIONS CONTINUED

Name & Address of Operators	Name of Mine & Mgr. or Supt.	County & Location	Facilities Operated	No. of Employees	1979 Production
University of California Lawrence Livermore Laboratory Hoe Creek Road Gillette, WY 82716	Hoe Creek Gasification D.S. Thompson	Campbell	Coal Gasification Experimental Station	60	
TOTAL:				5,265	71,445,178 T

COAL SUMMARY OF MINING MANHOURS, ACCIDENTS, FREQUENCY & SEVERITY RATES - 1980

Name of Operator or Company	Manhours		Frequency		Severity		Underground		Surface		No. of Underground Employees	Total No. of Employees
	Underground	Surface	Underground	Surface	Underground	Surface	Fatal	Nonfatal	Fatal	Nonfatal		
Prospect Point Coal Company Prospect Tipple		18,141		0.00		0.00			0	0		10
Resource Exploration Rimrock 1 & 2		196,580		2.03		31.54			0	2		75
Rosebud Coal Sales Company Rosebud Mine		470,398		0.00		0.00				0		240
Shell Oil Company Buckskin Mine-Office Only		41,310		1.26		2.53			0	2		27
Stansbury Coal Company Stansbury Mine	257,048	82,984	14.00	0.00	272.32	0.00	0	18	0	0	127	168
Thunder Basin Coal Company Black Thunder Mine		732,517		1.91		18.29			0	7		410
Wyodak Resources Devel. Corp. Wyodak Mine		103,919		15.39		169.36			0	8		52
TOTALS:	750,976	8,152,456	22.63	3.55	1815.77	167.90	1	85	1	147	408	5,922

These figures do not include Contractor's Data.

COAL OPERATIONS - 1980

Name & Address of Operators	Name of Mine & Mgr. or Supt.	County & Location	Facilities Operated	No. of Employees	1980 Production
AMAX Coal Company Bell Ayr P.O. Box 3005 Gillette, WY 82716	Belle Ayr Mine Ed Calahan	Campbell	Open Pit Coal Mine	404	16,106,093
AMAX Coal Company Eagle Butte P.O. Box 3005 Gillette, WY 82716	Eagle Butte Mine Fred VonKaenel	Campbell	Open Pit Coal Mine	212	8,440,000
Arch Minerals Corporation P.O. Box 490 Hanna, WY 82327	Seminoe Mine #1 James Ehrenhart	Carbon	Open Pit Coal Mine	225	2,500,000
Arch Minerals Corporation P.O. Box 530 Hanna, WY 82327	Seminoe Mine #2 Charles Kennedy	Carbon	Open Pit Coal Mine	270	1,828,852
Atlantic Richfield Company P.O. Box 1839 Gillette, WY 82716	Coal Creek Mine Howard Lowry	Campbell	Open Pit Coal - Under Construction	13	-0-
Big Horn Coal Company P.O. Box 724 Sheridan, WY 82801	Big Horn Coal Wm. M. Rosewarne	Sheridan	Open Pit Coal Mine	298	4,287,000
Black Butte Coal Company P.O. Box 98 Point of Rocks, WY 82942	Black Butte Coal James M. Wilson	Sweetwater	Open Pit Coal Mine, Processing Plant, Shop, Warehouse & Office	879	3,719,106
Bridger Coal Company P.O. Box 2068 Rock Springs, WY 82901	Jim Bridger Mine Glenn Goss	Sweetwater	Open Pit Coal Mine	404	6,453,302

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COAL OPERATIONS CONTINUED 1980

Name & Address of Operators	Name of Mine & Mgr. or Supt.	County & Location	Facilities Operated	No. of Employees	1980 Production
Carbon County Coal Company P.O. Box 830 Hanna, WY 82327	Carbon #1 Alex Sanders	Carbon	Underground Coal Mine	256	527,273
The Carter Mining Company P.O. Box 3007 Gillette, WY 82716	Caballo Mine T.D. Goddard	Campbell	Open Pit Coal Mine	112	1,974,164
The Carter Mining Company P.O. Box 3077 Gillette, WY 82716	Rawhide Mine E.L. Reed	Campbell	Open Pit Coal Mine	226	4,472,530
Cordero Mining Company P.O. Box 1449 Gillette, WY 82716	Cordero Mine Lowell B. Paige	Campbell	Open Pit Coal Mine	150	6,562,802
Delzer Construction Company P.O. Box 2723 Gillette, WY 82716	Fort Union Coal Mine Robert K. Hix	Campbell	Open Pit Coal Mine - Under Construction	13	10,962
Energy Development Company P.O. Box 600 Hanna, WY 82327	Vanguard #2 Edw. F. Ziolkowski	Carbon	Underground Coal Mine	199	877,637
F.M.C. Corporation Natural Resources Division P.O. Box 750 Kemmerer, WY 83101	Skull Point Mine John V. Corra	Lincoln	Open Pit Coal Mine & Shop	100	845,884
Glenrock Coal Company P.O. Box 159 Glenrock, WY 82637	Dave Johnston Mine David C. Nunenkamp	Converse	Open Pit Coal Mine	202	3,803,932

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COAL OPERATIONS CONTINUED

Name & Address of Operators	Name of Mine & Mgr. or Supt.	County & Location	Facilities Operated	No. of Employees	1980 Production
The Kemmerer Coal Company Frontier, WY 83121	Elkol Surface Mine James R. Brophy, Jr.	Lincoln	Open Pit Coal Mine & Preparation	271	1,733,740
The Kemmerer Coal Company Frontier, WY 83121	Sorensen Surface Mine James R. Brophy, Jr.	Lincoln	Open Pit Coal Mine & Preparation	333	2,348,838
Kerr McGee Coal Corporation P.O. Box 3014 Gillette, WY 82716	Clovis Point Mine S. Jess Larsen	Campbell	Open Pit Coal Mine, Preparation Plant, & Maintenance Shop	124	2,481,996
Kerr McGee Coal Corporation P.O. Box 3013 Gillette, WY 82716	Jacobs Ranch Mine Robert C. Scharp	Campbell	Open Pit Coal Mine, Preparation Plant, Train Loading, Maintenance Shop, & Office Facilities	298	8,246,072
Medicine Bow Coal Company P.O. Box 550 Hanna, WY 82327	Medicine Bow Mine Harold Combs	Carbon	Open Pit Coal Mine with Train Loading Facilities	231	1,819,622
Northwestern Resources Co P.o. Box 729 Thermopolis, WY 82443	Grass Creek Mine Monte J. Steffan	Hot Springs	Open Pit Coal Mine	4	18,284
Prospect Point Coal Company P.O. Box 8 Point of Rocks, WY 82942	Prospect Point Mine George Herne	Sweetwater	Coal Stockpile, Loadout & Preparation Plant	10	502,470 (Processed)
Resource Exploration and Mining, Inc. P.O. Box 750 Hanna, WY 82327	Rimrock #1 & #2 Mine Delmar Rames, V.P. Tom Bennett, Supt.	Carbon	Open Pit Coal Mine	75	692,087
Rosebud Coal Sales Company P.O. Box 780 Hanna, WY 82327	Rosebud 4A Strip Mine Jerry Smith	Carbon	Open Pit Coal Mine	240	1,890,540

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COAL OPERATIONS CONTINUED 1980

Name & Address of Operators	Name of Mine & Mgr. or Supt.	County & Location	Facilities Operated	No. of Employees	1980 Production
Shell Oil Company P.O. Box 818 Gillette, WY 82716	Buckskin Mine J.P. Franklin	Campbell	Open Pit Coal Mine-Under Construction	32	-0-
Stansbury Coal Company P.O. Box 2088 Rock Springs, WY 82901	Stansbury Mine Geo. Rittenberger	Sweetwater	Underground Coal Mine (Final Report)	168	228,110
Thunder Basin Coal Company P.O. Box 406 Wright, WY 82732	Black Thunder Mine A.I. Azimi	Campbell	Open Pit Coal Mine	410	10,548,996
Wyodak Resources Development Black Hills Power & Light Garner Lake Route Gillette, WY 82716	Wyodak Mine W.J. Westre	Campbell	Open Pit Coal Mine	52	
TOTALS:				6,231	93,986,433 Tons

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COAL OPERATIONS - 1981

Name & Address of Operator	Name of Mine & Manager or Superintendent	County	Facilities Operated	No. of Employees	1981 Production In Tons
AMAX Coal Company Belle Ayr Mine P.O. Box 3005 Gillette, WY 82716	Belle Ayr Mine G.E. Calahan	Campbell	Open Pit Coal Mine	403	15,256,750
AMAX Coal Company Eagle Butte Mine P.O. Box 3005 Gillette, WY 82716	Eagle Butte Mine Fred Von Kaenel	Campbell	Open Pit Coal Mine	248	8,144,997
Arch Mineral Corporation Seminoe No. 1 P.O. Box 490 Hanna, WY 82327	Seminoe No. 1 Mine Harold Combs	Carbon	Open Pit Coal Mine	69	597,961
Arch Mineral Corporation Seminoe No. 2 P.O. Box 530 Hanna, WY 82327	Seminoe No. 2 Mine Charles Kennedy	Carbon	Open Pit Coal Mine	236	2,756,453
Arch Mineral Corp./Rocky Mountain Medicine Bow Coal Co. P.O. Box 550 Hanna, WY 82327	Medicine Bow Coal James D. Ehrenhart	Carbon	Open Pit Coal Mine	228	2,025,455
Big Horn Coal Company P.O. Box 724 Sheridan, WY 82801	Big Horn Coal Mine William M. Rosewarne	Sheridan	Open Pit Coal Mine	229	2,753,913

COAL OPERATIONS - 1981

Name & Address of Operator	Name of Mine & Manager or Superintendent	County	Facilities Operated	No. of Employees	1981 Production In Tons
Black Butte Coal Company P.O. Box 98 Point of Rocks, WY 82942	Black Butte Coal Mine James M. Wilson	Sweetwater	Open Pit Coal Mine	601	4,390,072
Bridger Coal Company P.O. Box 2068 Rock Springs, WY 82901	Jim Bridger Mine Glenn A. Goss	Sweetwater	Open Pit Coal Mine	490	6,832,848
Carbon County Coal Company P.O. Box 830 Hanna, WY 82327	Carbon No. 1 Mine Joel A. Strid, Mgr. Howard Epperly, Supt.	Carbon	Underground Coal Mine	288	1,013,000
The Carter Mining Company Caballo Mine P.O. Box 3007 Gillette, WY 82716	Caballo Mine T.D. Goddard	Campbell	Open Pit Coal Mine	120	3,523,611
The Carter Mining Company Rawhide Mine P.O. Box 3007 Gillette, WY 82716	Rawhide Mine E.L. Reed	Campbell	Open Pit Coal Mine	231	6,154,313
Cordero Mining Company P.O. Box 1449 Gillette, WY 82716	Cordero Mine Earle M. Bagley	Campbell	Open Pit Coal Mine	167	8,312,578
Energy Development Company P.O. Box 600 Hanna, WY 82327	Vanguard II E.F. Ziolkowski	Carbon	Underground Coal Mine, Prep. Plant and Tipple	204	261,801

COAL OPERATIONS - 1981

Name & Address of Operator	Name of Mine & Manager or Superintendent	County	Facilities Operated	No. of Employees	1981 Production In Tons
F.M.C. Corporation P.O. Box 750 Kemmerer, WY 38101	Skull Point Mine John Corra	Lincoln	Open Pit Coal Mine	108	960,750
Fort Union Coal Mine P.O. Box 2737 Gillette, WY 82716	Fort Union Coal Mine Robert Hix	Campbell	Open Pit Coal Mine	20	34,887
Glenrock Coal Company Coal Company Route Glenrock, WY 82637	Dave Johnston Mine David C. Nunenkamp	Converse	Open Pit Coal Mine	226	3,628,932
The Kemmerer Coal Company Frontier, WY 83121	Elkol & Sorensen Mines James R. Brophy, Jr.	Lincoln	Open Pit Coal Mine and Prep. Plant	630	4,037,963
Kerr McGee Coal Corporation Caller Box 3014 Gillette, WY 82716	Clovis Point Mine S. Jess Larsen	Campbell	Open Pit Coal Mine	158	3,671,793
Kerr McGee Coal Corporation Caller Box 3013 Gillette, WY 82716	Jacobs Ranch Mine Robert C. Scharp	Campbell	Open Pit Coal Mine	311	8,722,262
Peter Kiewit Sons' P.O. Box 780 Hanna, WY 82327	Rosebud Coal Sales Co. Jerry Smith	Carbon	Open Pit Coal Mine	196	1,280,402

COAL OPERATIONS - 1981

Name & Address of Operator	Name of Mine & Manager or Superintendent	County	Facilities Operated	No. of Employees	1981 Production In Tons
Mobil Coal Producing, Inc. Box 3021 Gillette, WY 82716	Caballo Rojo Mine C. Nelson Futch	Campbell	Open Pit Coal Mine Under Construction	43	-0-
Northwestern Resources Co. P.O. Box 729-Broadway Thermopolis, WY 82443	Grass Creek Mine Monte J. Steffan	Hot Springs	Open Pit Coal Mine	8	35,617
Prospect Point Coal P.O. Box 8 Point of Rocks, WY 82942	Leucite Hills Mine George Herne	Sweetwater	Open Pit Coal Mine/Loadout Facility	9	-0-
Resource Exploration & Mining, Inc. P.O. Box 750 Hanna, WY 82327	Rimrock I & II Delmar D. Rames	Carbon	Open Pit Coal Mine	80	525,049
Rocky Mtn. Energy/Stansbury Coal Co. P.O. Box 2088 Rock Springs, WY 82901	Stansbury Mine Joseph C. Bozner	Sweetwater	Underground Coal Mine	93	18,558
Thunder Basin Coal Company P.O. Box 406 Wright, WY 82732	Black Thunder Mine A.I. Azimi	Campbell	Open Pit Coal Mine, Processing and Shipping	450	14,694,507

COAL OPERATIONS - 1981

Name & Address of Operator	Name of Mine & Manager or Superintendent	County	Facilities Operated	No. of Employees	1981 Production In Tons
Thunder Basin Coal Company P.O. Box 546 Wright, WY 82732	Coal Creek Mine D.W. Swetich	Campbell	Open Pit Coal Mine Under Construction	31	-0-
Triton Coal Co./Shell Oil Co. P.O. Box 3027 Gillette, WY 82716	Buckskin Mine John V. Burk	Campbell	Open Pit Coal Mine	70	350,647
Wyodak Resources Development Corp. RR 81 - Box G90 Gillette, WY 82716	Wyodak Coal Mine David J. Nicolarsen	Campbell	Open Pit Coal Mine	68	2,712,617
			TOTALS:	6,015	102,695,536

SUMMARY OF COAL MINING MANHOURS, ACCIDENTS, FREQUENCY AND SEVERITY RATES - 1981

NAME OF OPERATOR OR COMPANY	MAN HOURS		FREQUENCY		SEVERITY		UNDERGROUND		SURFACE		No. of Undrgrnd. Employs.	Total No. of Employs.
	Underground	Surface	Underground	Surface	Underground	Surface	Fatal	Non-Fatal	Fatal	Non-Fatal		
AMAX Coal Company Belle Ayre Mine		814,428		2.70		60.66				11		403
AMAX Coal Company Eagle Butte		491,288		2.44		62.69				6		248
Arch Mineral Corporation Seminoe No. 1		189,924		1.06		24.22				1		69
Arch Mineral Corporation Seminoe No. 2		535,582		4.11		165.43				11		236
Arch Mineral Corp. Rocky Mountain Medicine Bow Coal Co. Mine		512,255		2.34		40.60				6		228
Big Horn Coal Company Big Horn Coal		461,887		.87		2650.86			1	1		229
Black Butte Coal Company Black Butte Coal Mine		1,220,945		.33		16.87				2		601
Bridger Coal Company Jim Bridger Mine		955,033		2.30		1334.82			1	10		490
Carbon County Coal Company Carbon No. 1 Mine	405,871	148,165	27.59	1.75	350.85	116.09		56		1	211	288
The Carter Mining Company Caballo Mine		235,664		.85		16.97				1		120

STAFF'S DATA REQUEST NO. 30:

Please provide copies of any correspondence in which BB has specifically declined to or has been unable to increase supplies to Bridger in 2008 and 2009, based on requests from Idaho Power, IERCO, Pacific Minerals, or PacifiCorp.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 30:

In 2008, the Black Butte mine did not have excess production capacity. Mining was limited to two pits: Pit 8, a low sodium coal, and Pit 11, a high sodium coal. Low sodium coal production was limited as Pit 8 reserves were close to depletion. Due to limited Pit 8 supplies, Black Butte's deliveries to the Jim Bridger plant averaged in excess of 4.5 percent sodium in 2008 which, necessitated blending of low sodium coal from the Bridger Coal surface mine. The Bridger plant owners had several meetings with Black Butte in 2008 regarding the sodium content and limited supply. Sodium content remained high and excess supply non-existent until Black Butte subsequently opened Pit 14, in 2009. Without Bridger Coal surface mine deliveries in 2008, the Bridger plant would have sustained persistent MW deratings due to slagging.

In 2009, at the request of Idaho Power and PacifiCorp, Black Butte agreed to pre-deliver 100,000 tons of 2010 contracted Black Butte deliveries. The Bridger plant owners wanted to increase plant stockpile levels prior to January 19, 2010, when the labor agreement with the Utility Workers Union of America, Local 157 was due to expire. The pre-delivered coal was at the January 2010 contract price. A copy of the First Amendment to the Black Butte Coal Supply Contract has been attached.

The amendments being provided in response to Data Request No. 30 are confidential and will be provided separately in accordance with Protective Order No. 09-418 in this matter.

Q. PLEASE EXPLAIN YOUR THIRD MARKET ANALYSIS.

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

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

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

[21] Included in Confidential Exhibit Staff/205.

Table 7 – Third Market Analysis – Bridger Coal Costs

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

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

Table 8 – Third Market Analysis - Bridger Fuel Burn Expense

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

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

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

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

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

Table 9 – Fourth Market Analysis - Bridger Fuel Burn Expense

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

[23] See footnote 8.

Attachment - Response Staff DR 43

UE-214 / Idaho Power Company
March 9, 2010
Attachment OPUC 43

Seller	Mine	County	Contract Dates Begin	Contract Dates End	Contract Tonnage Total	Contract Tonnage Monthly	Actual Deliveries Tons	F.O.B.	Base Price $/Ton	Btu/lb	Mine Status
Lion Coal Co.	Swanson	Sweetwater	01/01/91	12/31/91		<= 3,000	19,883	Plant	$ 14.00	10000	Mine permanently closed in 1995
Lion Coal Co.	Swanson	Sweetwater	01/01/92	06/30/92		<= 3,000	18,207	Plant	$ 14.00	10000	"
Lion Coal Co.	Swanson	Sweetwater	07/01/92	12/31/92		<= 5,000	16,371	Plant	$ 14.00	10000	"
Lion Coal Co.	Swanson	Sweetwater	01/01/93	03/31/93		<= 5,000	12,847	Plant	$ 14.00	10000	"
Lion Coal Co.	Swanson	Sweetwater	04/01/93	12/31/93		<= 8,000	50,486	Plant	$ 13.00	10000	"
Lion Coal Co.	Swanson	Sweetwater	01/01/94	12/31/94		<= 11,000	64,648	Plant	$ 13.00	10000	"
Lion Coal Co.	Swanson	Sweetwater	01/01/95	03/31/95		<= 12,000	7,795	Plant	$ 13.00	10000	
Arch	Pilot Butte	Sweetwater	01/01/90	12/01/94	>=265,000 in 1990		538,980	Mine	$ 16.00	10750	Mine permanently closed in 1993
					>=300,000 in 1991						
Arch	Pilot Butte	Sweetwater	05/15/91	04/30/93	>=280,000 (5/15/01 - 4/30/92)		229,275	Mine	$15.40 - $16.40	10500	"
					>=300,000 (5/1/92 - 4/30/93)		471,131	Mine	$15.40 - $16.40	10500	"
Arch	Medicine Bow	Carbon	05/15/91	08/01/93	>=300,000		754,459	Mine	$13.00 - $14.05	10400	Mine permanently closed in 2003
Arch	Pilot Butte	Sweetwater	05/01/93	08/31/93	<=80,000		57,757	Mine	$ 13.44	10500	Mine permanently closed in 1993
Arch	Pilot Butte	Sweetwater	02/10/94	02/28/94	<=3,500		3,038	Mine	$ 11.00	10400	"
Arch	Medicine Bow	Carbon	10/10/94	11/30/94	<=60,000		35,686	Mine	$ 13.25	10400	Mine permanently closed in 2003
Cyprus	Shoshone	Carbon	08/01/92	12/31/92	<=60,000		-	Mine	$ 13.90	11200	Mine permanently closed in 2000
Peabody	Rochelle	Campbell	5/1/1990	8/31/1990			22,650	Mine	$ 4.85	8800	
Kennecott	Antelope	Converse	07/01/95	06/30/96	<=100,000		69,429	Mine	$ 4.60	8825	
Enron	Black Thunder	Campbell	05/01/00	06/30/00	<=60,000		58,858	Mine	$ 4.05	8800	

STAFF'S DATA REQUEST NO. 39:

As a follow-up to Staff Data Request Nos. 1 and 6, does Idaho Power believe that any cost per ton of surface mining operations is reasonable no matter how it affects total weighted cost and how it compares to third party surface mining costs per ton? Please explain.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 39:

No. Idaho Power Company believes that Oregon ratepayers benefit from the lowest cost fuel supply for the Bridger Plant. Such an analysis considers all of the costs to deliver and consume coal at the Bridger Plant (including capital). The Bridger mine, with the surface and underground operations, is the least cost alternative.

A comparison solely of Bridger Coal surface operating costs to other surface operations in southwest Wyoming is spurious. Unlike the Black Butte or Kemmerer mines, Bridger Coal is an integrated mining operation rather than separate surface and underground mines. Every mine, surface and underground, has a unique cost structure. Differences in mining methods, stripping ratios, coal extraction, and mine capitalization all affect the cost structure. Similarly to the Bridger mine surface operation, stripping ratios tend to increase over a mine's life. Though, the Bridger mine's stripping ratio is now higher than Black Butte's or Kemmerer's, *the decremental cost of Bridger Coal surface production is less than the cost of other supply options for the Bridger Plant.* Bridger Coal has already mined the lowest stripping ratio reserves – it still, however, remains the least cost supply for the Bridger Plant and Idaho Power Company ratepayers.

STAFF'S DATA REQUEST NO. 33:

As a follow-up to Idaho Power's response to Staff Data Request No. 1, please explain the difference in BCC total production cost per ton and BCC sale price per ton.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 33:

The BCC sales price per ton includes an operating margin, equal to the overall rate of return authorized in general rate cases where IERCO/BBC operations are treated as part of the regulated activities of the Company. The sales price is adjusted periodically as updated BCC mining expense data becomes available.

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 402

Exhibits in Support Of Reply Testimony

<u>REDACTED VERSION</u>

March 17, 2010

STAFF EXHIBIT 402

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.