



WENDY MCINDOO
503-595-3920
wendy@mrg-law.com

March 3, 2017

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97308-1088

Re: Docket No. UE 314
2017 Annual Power Cost Update ("APCU") – Reply Testimony of Nicole A.
Blackwell

Dear Filing Center:

Attached for filing in the above-referenced docket is an electronic copy of Idaho Power Company's Reply Testimony of Nicole A. Blackwell. Please contact this office with any questions.

Very truly yours,

Wendy McIndoo
Office Manager

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 314

IN THE MATTER OF IDAHO POWER)
COMPANY'S 2017 ANNUAL POWER)
COST UPDATE)
OCTOBER UPDATE)
_____)

IDAHO POWER COMPANY
REPLY TESTIMONY
OF
NICOLE A. BLACKWELL

March 3, 2017

1 **Q. Are you the same Nicole A. Blackwell who previously submitted Direct**
2 **Testimony in this proceeding?**

3 A. Yes.

4 **Q. What is the purpose of your reply testimony?**

5 A. The purpose of my Reply Testimony is to respond to the issues raised by the Public
6 Utility Commission of Oregon (“Commission”) Staff (“Staff”) Witnesses Mr. Scott
7 Gibbens and Mr. Lance Kaufman, in Staff’s January 31, 2017, Opening Testimony.

8 **Q. Please summarize the issues raised by Staff that you will respond to in your**
9 **Reply Testimony.**

10 A. My Reply Testimony responds to the following six issues raised by Staff in Opening
11 Testimony:

- 12 1. The forecast used to estimate total oil, handling, administrative, and general
13 (“OHAG”) expenditures at each of Idaho Power Company’s (“Idaho Power” or
14 “Company”) coal-fired facilities.
- 15 2. The allocation of net power supply expense (“NPSE”).
- 16 3. Idaho Power’s review of the Jim Bridger Plant’s (“Bridger Plant” or “Plant”)
17 fuel supply.
- 18 4. Bridger Coal Company (“BCC”) coal costs.
- 19 5. Idaho Power’s review of the depreciation policy for BCC.
- 20 6. Supporting workpapers for Idaho Power’s initial power cost filing.

21 **Q. Please explain Staff’s issue regarding the OHAG forecast.**

22 A. The first issue, raised by Mr. Gibbens, involves the Company’s forecast of total
23 OHAG expense at each of its coal-fired facilities. In his testimony, Mr. Gibbens
24 states, “the forecast is not updated on an annual basis”¹ and “there is no particular
25

26 ¹ Staff/100, Gibbens/7, line 6.

1 number of years used as a basis in determining a cost trend or average baseline for
2 the forecast.”² Mr. Gibbens asserts that “the forecast needs to be formulaic,
3 transparent, and follow a systematic approach, incorporating historical data and any
4 prevalent trends.”³

5 **Q. What is Mr. Gibbens’ recommendation for this issue?**

6 A. Mr. Gibbens recommends that the OHAG forecast be updated annually. He also
7 recommends that the forecast be based on a three-year historical average of actual
8 OAHG costs, with a growth (reduction) rate equal to the five-year historical average
9 growth (reduction) rate. Lastly, Mr. Gibbens recommends the update to the forecast
10 methodology be reflected in the Company’s upcoming 2017 March Forecast of
11 NPSE so as to include the most recent annual data.

12 **Q. Is Idaho Power willing to accept Mr. Gibbens’ recommendation?**

13 A. Yes. Idaho Power is willing to accept Mr. Gibbens’ recommendation for the purpose
14 of modeling OHAG within its Annual Power Cost Update (“APCU”) filings, and
15 intends to adopt his proposed methodology for the 2017 March Forecast and all
16 future APCU filings if the Commission ultimately approves the proposed adjustment.

17 **Q. Please explain Staff’s issue regarding the allocation of NPSE.**

18 A. The second issue, raised by Mr. Kaufman in his Opening Testimony, is related to
19 Idaho Power’s method of allocating power costs. Mr. Kaufman states that, “Idaho
20 Power does not allocate total power costs. Instead, Idaho Power uses a rate update
21 mechanism to allocate expenses incremental to the previous year.”⁴

22

23

24 ² Staff/100, Gibbens/7 lines 22-23.

25 ³ Staff/100, Gibbens/7 lines 24-25.

26 ⁴ Staff/200, Kaufman/2 lines 8-9.

1 **Q. Do you agree with Mr. Kaufman's characterization of the rate calculation**
2 **methodology utilized for the APCU?**

3 A. Yes. The Company agrees with Mr. Kaufman that Idaho Power uses a rate update
4 mechanism to allocate expenses incremental to the previous year. Specifically,
5 power costs are allocated to the Oregon jurisdiction by multiplying the system
6 incremental per-unit cost by the forecasted Oregon jurisdictional loss-adjusted
7 normalized sales for the test period. This allocation method has been used and
8 accepted in every APCU filing since its inception in Docket No. UE 195.

9 **Q. What is Mr. Kaufman's recommendation for this issue?**

10 A. Mr. Kaufman recommends using a "total cost method."⁵ It is the Company's
11 understanding that under Mr. Kaufman's recommended total cost method, the
12 Oregon jurisdictional revenue requirement would be calculated using the system per-
13 unit cost for the test period, not the incremental per-unit cost. Furthermore, base
14 rates for each service schedule would be reset each year rather than applying an
15 incremental adjustment to base rates each year.

16 **Q. Can you provide an example to illustrate Mr. Kaufman's recommendation?**

17 A. Yes. For the 2017 October Update, the system per-unit cost was \$26.06 per
18 megawatt-hour ("MWh") (\$382.1 million/14.661 million MWh). The 2016 October
19 Update system per-unit cost was \$23.93 per MWh (\$349.8 million/14.617 million
20 MWh). To determine the Oregon jurisdictional revenue requirement for the 2017
21 October Update, the Company multiplied the system incremental per-unit cost of
22 \$2.13 per MWh ($\$26.06 - \$23.93 = \2.13) by the Oregon jurisdictional loss-adjusted
23 sales for the test period of 686,534.333 MWh. It is Idaho Power's understanding that
24 because the system per-unit costs for the 2017 October Update and 2016 October

25 ⁵ Staff/200, Kaufman/4 line 19.
26

1 Update were not calculated using the same loss-adjusted normalized sales figure in
2 the denominator, Mr. Kaufman believes that power costs are not accurately
3 recovered.⁶ As such, Mr. Kaufman recommends that the Company multiply the
4 system per-unit cost of \$26.06/MWh by the Oregon jurisdictional sales of
5 686,534.333 MWh to determine the total Oregon jurisdictional revenue requirement,
6 not the incremental revenue requirement.

7 **Q. Have the parties to this case discussed how to address Mr. Kaufman's**
8 **recommendation?**

9 A. Yes. It is Idaho Power's understanding that parties will discuss Staff's rate
10 calculation recommendation at an upcoming workshop scheduled for March 6, 2017.
11 Should the parties reach an agreement to modify the current rate calculation, such
12 changes would be reflected in the 2017 March Forecast.

13 **Q. Please explain the Company's understanding of the issue presented by Staff**
14 **regarding the Bridger Plant fuel supply.**

15 A. The third issue, raised by Mr. Kaufman in his Opening Testimony, is related to Idaho
16 Power's oversight of the Bridger Plant's fuel supply. Mr. Kaufman states, "between
17 2013 and 2015, Idaho Power did not analyze the appropriateness of purchasing coal
18 from BCC."⁷

19 **Q. Please briefly describe the BCC fuel supply for the Bridger Plant.**

20 A. The Bridger Plant was designed and constructed as a "mine-mouth" plant, which
21 means it is physically located next to the coal mine that supplies the majority of its
22 coal. The adjacent mine is owned by BCC, which is jointly owned by PacifiCorp and
23

24
25 ⁶ Staff/200, Kaufman/2 lines 4-6.

26 ⁷ Staff/200, Kaufman/6 lines 14-15.

1 Idaho Power, on the same two-thirds/one-third basis as the Bridger Plant.⁸ This
2 mine-mouth arrangement ensures that the Bridger Plant has access to a continuous
3 and reliable supply of coal.

4 Coal is delivered to the Bridger Plant from the BCC mine by use of a large
5 conveyor belt system that transports and delivers coal directly from the mining
6 operation to the Plant. This type of mine-mouth plant operation has several
7 advantages over an operation where the coal is delivered from another location.
8 Most notably, it eliminates the need to ship coal over long distances in order to
9 supply the Plant. BCC has supplied the Bridger Plant with coal since 1974.

10 **Q. Do you agree with Mr. Kaufman’s statement that “between 2013 and 2015,**
11 **Idaho Power did not analyze the appropriateness of purchasing coal from**
12 **BCC?”⁹**

13 A. No. As an engaged partner in the Bridger Plant and BCC, Idaho Power continuously
14 provides input, oversight, and review of all operations, including the fueling strategy
15 for the Bridger Plant. At least annually, Idaho Power and PacifiCorp work together to
16 develop a BCC mine plan using a 10-year planning horizon to develop a strategy for
17 least-cost, least-risk fueling of the Bridger Plant. The BCC mine plan was last
18 updated in late 2016. The Company also participates in the development of more
19 comprehensive fueling plans based on the life-of-plant approximately every two
20 years.

21 Idaho Power also participates in the development of Bridger Plant long-term
22 fuel plans, which are filed by PacifiCorp, the Plant operator, in compliance with Order

23
24 ⁸ BCC is one-third owned by Idaho Energy Resources Company (“IERCo”), a subsidiary of Idaho
25 Power, and two-thirds owned by Pacific Minerals Inc., a subsidiary of PacifiCorp. The coal supply agreement
between Idaho Power and IERCo was approved by the Commission in Order No. 91-567 in Docket No. UI 107.

26 ⁹ Staff/200, Kaufman/6 lines 14-15.

1 No. 13-387.¹⁰ In Order No. 13-387, the Commission approved a process under which
2 PacifiCorp files a long-term fuel plan with its Transition Adjustment Mechanism
3 (“TAM”) filing to permit a multi-year examination of the prudence of the Bridger Plant
4 fuel supply costs. As an engaged partner, Idaho Power is involved in the
5 development of these plans. PacifiCorp filed the first Long-Term Fuel Supply Plan
6 on December 30, 2015.

7 **Q. Has Idaho Power performed any recent analysis of long-term fuel costs for the**
8 **Bridger Plant?**

9 A. Yes. In 2016, Idaho Power independently performed analyses to evaluate the
10 Present Value Revenue Requirement impact of four life-of-mine scenarios presented
11 by PacifiCorp, the owner-operator. These analyses incorporated the cost of the BCC
12 coal supply provided by the owner-operator, and third-party fuel supply needed for
13 Idaho Power’s required output of the Bridger Plant. Idaho Power provided this
14 analysis to Staff in response to Staff’s Data Request (“DR”) No. 20 on January 27,
15 2017.

16 **Q. Do you agree with Mr. Kaufman’s comments regarding Idaho Power’s**
17 **“oversight” of the Bridger Plant’s fuel supply?¹¹**

18 A. No. Mr. Kaufman suggests that Idaho Power does not review the actions proposed
19 or taken by the Bridger Plant’s majority owner. Idaho Power works closely with its
20 ownership partner and does not consider its minority ownership interest an
21 exemption to this obligation.

22 As detailed above, Idaho Power recently performed an independent analysis
23 with respect to the appropriate fueling strategy for the Bridger Plant. Another recent

24 ¹⁰ *In the matter of PacifiCorp’s 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No.
25 13-387 at 7 (October, 28, 2013).

26 ¹¹ Staff/200, Kaufman/6-7

1 example of Idaho Power’s direct involvement in the decision-making of Bridger Plant
2 operations is the Company’s attendance at the January 20, 2017, and March 1,
3 2017, workshops regarding the long-term fueling strategy for the Bridger Plant. As
4 part of Order No. 16-482 in PacifiCorp’s 2017 TAM filing, Docket No. UE 307, the
5 Commission directed PacifiCorp, Staff, and parties to informally meet and discuss
6 the long-term fuel supply plan for the Bridger Plant. Although the workshop was part
7 of PacifiCorp’s TAM filing and Idaho Power was not a party to the case, the
8 Company attended the workshops in order to provide input and stay informed on
9 discussions pertaining to fueling strategies for the Bridger Plant.

10 **Q. What is Mr. Kaufman’s recommendation for this issue?**

11 A. Mr. Kaufman recommends “the Commission affirm or clarify that minority owners of
12 coal plants have a duty to review all major actions proposed or taken by the facility’s
13 majority owners”¹²

14 **Q. Is Idaho Power opposed to the language proposed by Mr. Kaufman?**

15 A. No. Idaho Power has no objection to the Commission affirming or clarifying this
16 point, but does not feel it is necessary. As discussed above, Idaho Power is a fully
17 engaged and active partner regarding the fueling source decisions for the Bridger
18 Plant.

19 **Q. Please explain Staff’s concern regarding BCC coal costs.**

20 A. The fourth issue, raised by Mr. Kaufman, relates to the inclusion of depreciation
21 expense in BCC coal costs. In his testimony, Mr. Kaufman states, “Idaho Power
22
23
24

25 ¹² Staff/200, Kaufman/7 lines 12-14.
26

1 appears to be recovering depreciation costs for [BCC] assets that are not included in
2 rate base.”¹³

3 **Q. What is Mr. Kaufman’s recommendation for this issue?**

4 A. Mr. Kaufman recommends that depreciation costs associated with plant that is not
5 currently in rate base be excluded from coal costs.¹⁴ Mr. Kaufman asserts that he
6 did not have sufficient data at the time his testimony was submitted to propose a
7 specific dollar adjustment. However, he intends to adjust 2017 BCC coal costs by
8 the amount of depreciation expense included in the BCC coal cost that is associated
9 with plant added after Idaho Power’s most recent general rate case.¹⁵

10 **Q. Do you agree with Mr. Kaufman’s conclusion and subsequent**
11 **recommendation?**

12 A. No. For reasons I will detail in my testimony, BCC costs included in the Company’s
13 NPSE appropriately reflect the current cost of procuring coal for use at the Bridger
14 Plant. The treatment of the BCC coal sales agreement has already been approved
15 by the Commission, and the inclusion of these costs in Company rates appropriately
16 aligns with Commission precedent.

17 **Q. Please describe the relationship between Idaho Power and BCC.**

18 A. Idaho Power owns 100 percent of IERCo, which has a one-third joint venture interest
19 in BCC. Idaho Power accounts for IERCo as an equity method investment.
20 Separate records and accounts for IERCO are maintained and the operations of
21

22 ¹³ Staff/200, Kaufman/7 lines 17-18. Mr. Kaufman’s testimony states, “Idaho Power appears to be
23 recovering depreciation costs for assets that are not included in base rates.” Idaho Power assumes Mr.
24 Kaufman intended to state, Idaho Power appears to be recovering depreciation costs for BCC assets that are
25 not included in rate base, not base rates.

25 ¹⁴ Staff/200, Kaufman/8 lines 6-7.

26 ¹⁵ Staff/200, Kaufman/8 lines 14-19.

1 IERCO as a joint venturer in BCC are subject to regulatory review and scrutiny
2 together with those of Idaho Power during general rate cases.

3 For general rate case revenue requirement determinations, Idaho Power
4 includes its investment in IERCo as a component of utility rate base, and includes as
5 an offset to the utility revenue requirement the test-year IERCo earnings in the form
6 of electric operating income. Coal delivered from BCC to the Bridger Plant is priced
7 at the mine's cost plus an operating margin equal to the revenue requirement on
8 IERCo rate base from the most recent general rate case. This pricing approach
9 ensures that the Company does not earn more than its allowed return on its
10 investment in IERCo between rate cases.

11 **Q. Are depreciation costs for BCC assets included in the cost of coal?**

12 A. Yes. In 1974, PacifiCorp and Idaho Power entered into a long-term coal sales
13 agreement with BCC. Pursuant to that agreement, and its restatements and
14 amendments, the coal sales price is computed based on BCC's total projected costs,
15 including depreciation, as well as a calculated operating margin as provided for in
16 Idaho Power's rate base. In other words, under the terms of the coal sales
17 agreement, the coal sales price ultimately reflects current costs associated with
18 procuring coal for use at the Bridger Plant, including the cost of depreciable assets
19 required to extract coal at the mine. The sales price is adjusted periodically as
20 updated cost data becomes available. Each time the sales price is adjusted the
21 parties execute an amendment to the agreement.

22 **Q. Has the Commission approved the Company's current coal sales agreement?**

23 A. Yes. The most recent coal sales agreement was approved by the Commission in
24 Order No. 91-567 in Docket No. UI 107. In Order No. 91-567, the Commission
25 stated:
26

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

6 The transfer price for the coal which is provided by
7 Bridger to [Idaho Power] shall be billed at actual cost. . . . The
8 Commission concludes that the agreement is fair and
9 reasonable and not contrary to the public interest.

10 [Idaho Power's] contract with Bridger has and shall
11 continue to be recognized for rate-making purposes.
12 Expenditures made should be charged to accounts in the
13 manner directed by the Federal Energy Regulatory
14 Commission regulations and by the Commission's rules.¹⁶

15 **Q. Are assets associated with BCC treated in the same manner as the Company's**
16 **standard utility assets from a ratemaking perspective?**

17 **A.** No. BCC is a non-utility entity, and therefore its assets are treated differently for
18 ratemaking purposes than the Company's standard utility assets. Under traditional
19 ratemaking for standard utility assets, the Company invests in rate base on behalf of
20 customers, then requests approval to collect through rates the cost of its investment
21 and a fair rate of return through a ratemaking proceeding at the Commission.
22 Alternatively, BCC is a non-utility entity, and its assets have been subject to
23 treatment that differs from that of standard utility assets. Because BCC costs
24 (including depreciation expense associated with assets in service at the mine) reflect
25 the cost of procuring fuel for the Bridger Plant, they have been recognized by the
26 Company and the Commission as a fuel expense. Therefore, when the Company
prepares its APCU filings and updates fuel costs associated with its generation
facilities, costs at BCC are updated to reflect assets currently in service at the mine,

¹⁶ *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, Docket No. UI 107, Order No. 91-567 at 4 (April 25, 1991).*

1 whether assets have been added, retired, or sold. This ensures that customer rates
2 are reflective of the current cost of procuring fuel for the Bridger Plant.

3 **Q. Has the Commission approved this ratemaking treatment in prior**
4 **proceedings?**

5 A. Yes. The Commission has recognized and approved BCC costs as fuel expense in
6 Docket Nos. UE 92, UE 167, UE 203, UE 213, UE 214, UE 222, UE 233, UE 242,
7 UE 257, UE 279, UE 293, and UE 301.

8 **Q. What customer benefits result from the existing treatment of BCC expense**
9 **within the context of the APCU?**

10 A. As previously discussed, the existing treatment of BCC expense within the context of
11 the APCU ensures that costs included in customer rates remain current with regard
12 to the expected cost of procuring fuel for the Bridger Plant. The Company views the
13 update to BCC expense in the same manner as updating expected gas prices, heat
14 rates, and other variables included in the annual APCU filing that are intended to
15 maintain alignment between NPSE included in rates and actual NPSE incurred by
16 the Company. Depreciation expense associated with BCC assets is only included in
17 fuel costs if an asset is currently used and useful, meaning customers only pay for
18 equipment that is a current operating cost at the mine.

19 Additionally, updating BCC costs to reflect depreciable assets currently in
20 service can serve as an immediate benefit to customers in the event that mine
21 assets are sold. A recent example of this occurred in Docket No. UP 334, in which
22 the disposition of BCC assets resulted in lower overall fuel costs to customers. In
23 Docket No. UP 334, the Company requested an order authorizing the sale by BCC of
24 a Page 732E Dragline ("Dragline") and associated parts. In the Application, Idaho
25 Power explained that the Dragline, which is a large, earth moving machine, was put
26 into service in 1974 for surface mining operations. The Dragline was taken out of

1 service in 1998 because it was too small to continue to operate economically at the
2 BCC surface mine. BCC attempted to negotiate the sale of the Dragline to various
3 parties over time, and eventually sold the asset in 2016 at approximately \$190,000
4 above net book value. As pointed out in Staff's Report:

5 The proceeds will flow through BCC's income statement and
6 be reflected in the cost of coal burned at the Jim Bridger
7 generating plant, reducing net power costs. Fuel costs are
8 updated annually through the Company's fuel cost adjustment
9 mechanism; *therefore, lower fuel costs for the Company result
10 in lower costs to customers, regardless of the timing of general
11 rate cases.*¹⁷

12 It is also important to note that customer rates did not reflect expenses
13 associated with the Dragline between 1998, when the Dragline was taken out of
14 service, and 2016, when the Dragline was sold. In its Application, Idaho Power
15 explained:

16 Although the Dragline has not been in service, under the
17 Commission-approved ratemaking treatment of IERCo,
18 customer rates have not been adversely impacted.
19 Depreciation expense is part of the overall expenses of BCC's
20 coal operations, initially appearing in fuel inventory costs at
21 Idaho Power as coal sales from BCC to Idaho Power, and is
22 ultimately reflected in Federal Energy Regulatory Commission
23 ("FERC") Account 501 – Fuel Expense Coal when the coal is
24 burned at the plant. When the Dragline was taken out of
25 service, depreciation ceased and therefore was not reflected in
26 fuel inventory costs, resulting in lower overall costs to Idaho
Power and its customers.¹⁸

**Q. Does Idaho Power believe an adjustment is warranted with respect to
depreciation expense embedded in BCC costs?**

¹⁷ *In the Matter of the Application of Idaho Power Company for an Order Authorizing the Sale of a
Dragline and Associated Parts*, Docket No. UP 334, Revised Staff Report for January 12, 2016, Public Meeting
(Item No. CA8) at 3-4 (January 4, 2016) (emphasis added).

¹⁸ *In the Matter of the Application of Idaho Power Company for an Order Authorizing the Sale of a
Dragline and Associated Parts*, Docket No. UP 334, Idaho Power's Application at 3 (December 4, 2015).

1 A. No. Idaho Power and PacifiCorp have a significant investment in the BCC mining
2 operation which has benefited customers with a long-term, reliable, and fairly priced
3 source of fuel. The fixed investment costs of BCC should continue to be recovered
4 in rates, as the existing ratemaking treatment complies with the Commission-
5 approved coal sales agreement and ensures that customer rates reflect the current
6 costs of procuring coal for the Bridger Plant. Depreciation expense associated with
7 assets currently in service and required in the operations of the Bridger mine is
8 appropriately reflected in the Company's APCU filing and should not be adjusted.

9 **Q. Please explain Staff's issue regarding the depreciation policy for BCC.**

10 A. The fifth issue, raised by Mr. Kaufman in his Opening Testimony, relates to Idaho
11 Power's review of the depreciation policy for BCC. In his testimony, Mr. Kaufman
12 states that, "Idaho Power does not appear to monitor the depreciation policy for
13 BCC."¹⁹

14 **Q. Do you agree with Mr. Kaufman's conclusion?**

15 A. No. As discussed previously, Idaho Power is an engaged partner in BCC. As part of
16 the BCC Management Committee, Idaho Power oversees all operational decisions at
17 BCC, including short and long-term strategy issues, mine plans, approval of all
18 capital and operations and maintenance expenditures and depreciation practices.

19 Mr. Kaufman mischaracterizes Idaho Power's engagement in BCC decisions
20 based on the Company's response to Staff's DR No. 23, in which Idaho Power
21 requested additional time to obtain BCC depreciation analyses from its operating
22 partner.²⁰ The request for additional time was the result of the need to gather
23 information from the owner-operator, PacifiCorp; this is not an indication that Idaho

24
25 ¹⁹ Staff/200, Kaufman/8 lines 3-4.

26 ²⁰ Staff/200, Kaufman/8 FN 11.

1 Power does not monitor the depreciation policy at the mine, but simply an indication
2 that Idaho Power does not serve as the keeper of the BCC joint venture records
3 requested by Staff. The Company has since responded to Staff with supplemental
4 information to DR No. 23. While Idaho Power does not maintain the depreciation
5 analyses of BCC assets, the Company is fully engaged in BCC operational
6 decisions, including its deprecation practices. This assertion is further supported by
7 the Company's response to Staff's DR No. 21, in which the Company provided the
8 list of depreciable assets in use at the Bridger mine and their corresponding
9 depreciable lives. The information provided in response to DR No. 21 is maintained
10 and monitored by Idaho Power as an active partner at BCC.

11 **Q. What is Mr. Kaufman's recommendation on this issue?**

12 A. Mr. Kaufman recommends that the Commission direct Idaho Power to review the
13 depreciation practices of its operating partner on an ongoing basis.

14 **Q. Do you agree with Mr. Kaufman's recommendation?**

15 A. Idaho Power has no objection to the Commission citing the importance of reviewing
16 the depreciation practices of its operating partner on an ongoing basis. However,
17 Idaho Power does not require a reminder by the Commission as this is a current
18 practice of the Company. As discussed above, Idaho Power is fully engaged in BCC
19 operational decisions.

20 **Q. Please explain Staff's issue regarding workpapers.**

21 A. The sixth issue, raised by Mr. Kaufman in his Opening Testimony, relates to
22 workpapers filed in support of the Company's October Update filing. In his
23 testimony, Mr. Kaufman states, "Idaho Power did not provide workpapers with its
24 initial power cost filing."²¹

25 ²¹ Staff/200, Kaufman/9 line 5
26

1 **Q. What is Mr. Kaufman's recommendation on this issue?**

2 A. Mr. Kaufman recommends that Idaho Power, Staff, and other parties work together
3 to collaboratively update Idaho Power's filing requirements for future power cost
4 filings.

5 **Q. Is Idaho Power open to modifying the workpapers provided with its APCU**
6 **filings?**

7 A. Yes. Idaho Power agrees that it would be in the best interest of the Company, Staff,
8 and other parties to establish guidelines which would detail the workpapers to be
9 filed in all future APCU filings. Parties discussed this issue at the February 16, 2017,
10 Settlement Conference, and agreed to address this issue at the upcoming workshop
11 scheduled for March 6, 2017.

12 **Q. Have you responded to all of the issues addressed by Staff in Opening**
13 **Testimony?**

14 A. Yes. All of the issues or concerns identified in Staff's Opening Testimony have been
15 addressed and reasonably explained.

16 **Q. Does this conclude your Reply Testimony?**

17 A. Yes, it does.
18
19
20
21
22
23
24
25
26