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March 1, 2018

VIA ELECTRONIC AND US MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: UE 333 - In the Matter of IDAHO POWER COMPANY'S 2018 Annual Power Cost Update

Attention Filing Center:

Enclosed for filing in the above-referenced matter is Idaho Power Company's Confidential Reply Testimony and Exhibit of Nicole A. Blackwell (Idaho Power/200-201) and Reply Testimony and Confidential Exhibit of Tom Harvey (Idaho Power/300-301). Confidential copies will be sent to the Filing Center and parties who have signed the Protective Order (Order No. 17-443) via US Mail. Please note that Nicole Blackwell's Exhibit 201 is being provided on a CD.

Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till
Legal Assistant

Attachments

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 333

IN THE MATTER OF IDAHO POWER COMPANY'S 2018 ANNUAL POWER COST UPDATE	)
OCTOBER UPDATE	)

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

NICOLE A. BLACKWELL

March 1, 2018

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

A. Yes.

Q. What is the purpose of your Reply Testimony?

A. The purpose of my Reply Testimony is to respond to issues raised by the Public Utility Commission of Oregon ("Commission") Staff ("Staff") witnesses Ms. Rose Anderson, Mr. Scott Gibbens, and Mr. Lance Kaufman in Staff's February 12, 2018, Opening Testimony.

Q. Are any other witnesses sponsoring Reply Testimony for Idaho Power Company ("Idaho Power" or "Company")?

A. Yes. Tom Harvey is also sponsoring Reply Testimony for Idaho Power. Mr. Harvey will address issues presented by Mr. Kaufman in his Opening Testimony that are related to the near-term and long-term fueling plan for the Jim Bridger coal-fired plant ("Bridger").

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

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

1. Forecast versus actual Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses for April 2016 – March 2017.
2. Energy Imbalance Market ("EIM") benefits and costs for the first year of participation.
3. Idaho Power's rate spread.
4. Bridger Coal Company ("BCC") coal costs.
5. Idaho Power's depreciation policy for BCC.

PURPA Forecast

Q. Please describe Staff's concern regarding the PURPA forecast.

A. The first issue, raised by Ms. Anderson, involves the Company's forecast of PURPA expense included in the 2016 Annual Power Cost Update ("APCU"), Docket No. UE 301. Staff states, "the forecast in the 2016 APCU was 20 percent above actual PURPA expenses for the 2016 power cost year."[1]

Q. Is Staff's statement accurate?

A. Yes. Forecast PURPA expenses for the 2016 APCU October Update were 20 percent above actual PURPA expenses for the 2016 power cost year.

Q. Was the variance in forecast versus actual PURPA expense for the 2016 APCU an anomaly?

A. Yes. As pointed out by Ms. Anderson in her Opening Testimony: "The PURPA forecast was reasonably accurate in the 2014 and 2015 APCU filings . . . . In the two previous power cost years, the error [difference in forecast versus actual PURPA expense] was much smaller. The PURPA forecast exceeded actuals by 2.3 percent in the 2014 power cost year and by 8.1 percent in the 2015 power cost year."[2] Idaho Power agrees with Ms. Anderson's statement that the PURPA forecast was reasonably accurate in the 2014 and 2015 APCU filings.

Additionally, the forecast for the 2017 APCU also demonstrated a smaller variance than the anomalous 2016 forecast. The forecast of PURPA expenses included in the 2017 APCU October Update for the time period of April 2017 – January 2018, for which actual expenses for comparison are available, was approximately $189.0 million. As of January 31, 2018, actual PURPA expense for the April 2017 – January 2018 time period was $178.9 million, which is 5.4 percent lower than forecast.

[1] Staff/100, Anderson/9, lines 10-11.

[2] Staff/100, Anderson/9, lines 9-10 and 16-18.

The Company believes this is a reasonable deviation in forecast and actual expenses and is more in line with historical variances. The Company also believes that the accuracy of the 2014, 2015, and 2017 APCU PURPA forecasts further indicates that the deviation in forecast versus actual PURPA expense for the 2016 APCU was atypical.

Q. What is Ms. Anderson's recommendation for this issue?

A. Ms. Anderson recommended that "Idaho Power explain the reasons PURPA expenses were over-estimated to such a large degree in the 2016 APCU and propose steps to remedy any issues with the PURPA forecast if necessary." [3]

Q. Please explain the difference in forecast versus actual PURPA expense for the 2016 APCU.

A. As pointed out in the Company's testimony in the 2016 APCU October Update, the PURPA forecast included 23 new PURPA contracts, which represented a 22 percent increase in the number of PURPA projects under contract at that time. The new projects contributed to forecast generation of 361 average-megawatts ("aMW) for the 2016 October Update, a 40 percent increase from the forecast generation of 258 aMW included in the 2015 October Update. A breakdown of the 23 new contracts included 14 solar projects, five wind projects, three hydro projects, and one cogeneration project.

As discussed in the Company's response to Staff's Data Request No. 2 in the 2018 APCU, for new PURPA projects, the Company does not have historical actual generation data and therefore must rely on the estimated generation output provided by the PURPA project to determine forecast generation and expense for the APCU. Additionally, forecast generation for new PURPA projects expected to come online

[3] Staff/100, Anderson/10, lines 9-11.

during the APCU test year is annualized, meaning if a project comes online or is scheduled to come online for any month of the reporting period, it is assumed the project will be online for all months of that reporting year. This process has been utilized since the APCU mechanism was implemented in order to establish a base or normalized level of PURPA expense to be included in rates.

In the case of the 2016 APCU October Update, the Company had to rely on forecast generation provided by the 23 new PURPA contracts, as there was no historical generation available from these projects. Additionally, 12 of the new projects are located in Oregon, where the standard contract agreements for PURPA projects require less granularity for project-provided forecast generation, as compared to Idaho contracts. In accordance with Oregon standard contract agreements for PUPRA projects, the projects are only required to provide an annual generation estimate, as compared to Idaho contract agreements for PURPA projects, which require the project to provide hourly or monthly generation estimates. Furthermore, the new projects expected to come online during the 2016 APCU included utility scale solar and wind resources ranging in size from 4.5 megawatts ("MW") to 80 MW, which further exacerbated the potential for differences between forecast and actual generation due to the large and intermittent energy output of these projects.

In addition to relying on the estimated generation output provided by new PURPA projects, Idaho Power also must rely on the expected operation date provided by new PURPA projects. When Idaho Power enters into new agreements with PURPA projects, the contracts require the expected or scheduled operation date; however, unless the project informs Idaho Power of a desire to change the scheduled operation date, the Company has no way to determine whether the expected date is realistic until the scheduled operation date is either achieved or missed. The large number of new contracts that came online during the 2016 APCU, and the uncertainty around the expected generation of these projects as well as their actual operation dates, was the primary contributing factor to the variance between forecast and actual expenses.

Q. Has the Company quantified the portion of the total variance that was attributed to new projects coming online?

A. Yes. Protected Information Exhibit 1 presents the difference in the 2016 APCU October Update PURPA forecast and actual PURPA expenses for the 2016 APCU test period. As shown on line 130, $26.7 million, or 77 percent, of the total $34.6 million variance in forecast and actual PURPA expense was attributed to the new projects. Of the $26.7 million variance, $3.1 million was related to two projects that did not come online during the year as expected, $18.8 million was related to 11 projects that came online later than scheduled and forecast generation exceeded actual generation, and $4.8 million was related to 10 projects for which forecast generation exceeded actual generation.

Q. Were there any notable variances related to existing projects?

A. Yes. There were some notable variances related to existing projects. A 10 MW thermal project that had been online for 20 years and was expected to request a replacement Energy Sales Agreement during the 2016 APCU test period did not, which accounted for approximately $1.4 million of the total $34.6 million variance, as shown on line 70. Additionally, generation unexpectedly declined significantly for an existing five MW biomass project in 2016 and 2017, so much so that the project owes Idaho Power capacity refund payments for not meeting contractual generation requirements. This project accounted for approximately $1.4 million of the total $34.6 million variance, as shown on line 115.

Q. Have the PURPA expenses included in the 2016 APCU been reviewed by Staff in previous dockets?

A. Yes. The forecast of PURPA expenses in question has been previously reviewed by Staff and approved by the Commission in the 2016 APCU docket, as well as nine of the 12 months of the actual PURPA expenses included in the 2016 Power Cost Adjustment Mechanism ("PCAM"), Docket UE 320. Staff conducted a thorough investigation of forecast PURPA contract expenses included in Idaho Power's 2016 APCU. Staff's testimony in the 2016 APCU states, "Staff felt that a close examination of PURPA contracts was warranted given the large portion of Net Power Supply Expense ("NPSE") that they make up (nearly 60 percent) . . . . Staff found no evidence of over-inflated projected energy outputs and had no recommendation regarding PURPA contracts at the time."[4]

Q. Does Idaho Power believe that the variance identified by Staff is relevant to this case?

A. No. Idaho Power believes that Staff conducted a thorough investigation of the PURPA forecast in the 2016 APCU, as well as the majority of the actual PURPA expenses for the 2016 APCU test period through the 2016 PCAM, and that a re-examination of these costs is not pertinent to the 2018 APCU filing at issue.

Q. Does the Company believe its PURPA forecast methodology needs to be adjusted?

A. No. As mentioned previously, the difference in the 2016 APCU October Update PURPA forecast and actual PURPA expense for the 2016 APCU test period was an anomaly due to the large number of new projects that were expected to come online during the year. Idaho Power does not anticipate another influx of new PURPA projects such as it experienced in the 2016 – 2017 time period. Consequently, Idaho Power does not believe that a modification to its PURPA forecast is warranted at this

[4] *In the Matter of Idaho Power Company's 2016 Annual Power Cost Update*, Docket No. UE 301, Staff/200, Gibbens/11 (April 15, 2016).

time. Rather, Idaho Power recommends that deviations in forecast and actual PURPA expenses continue to be monitored and modifications to the PURPA forecast be evaluated in the future, if necessary.

Q. Does Idaho Power have any final thoughts regarding Staff's concern about the accuracy of the 2016 APCU October Update PURPA forecast?

A. Idaho Power is concerned that Staff may be under the impression that the Company over-recovered NPSE for the 2016 APCU test period as a result of the variance in forecast and actual PURPA expense. This is not the case, however. As a result of actual PURPA generation coming in 0.88 million megawatt-hours ("MWh") below forecast, of which 0.76 million MWh was attributed to the 23 new projects, Idaho Power had to serve load through other resources. In other words, Idaho Power's forecast of non-PURPA-related generation was under-forecast because expected PURPA generation did not materialize. This is evident by Idaho Power's under-recovery of approximately $2.5 million in Oregon-allocated NPSE for April 2016 – December 2016 (nine of the 12 months of the 2016 APCU test period), as demonstrated in the 2016 PCAM.[5]

<u>EIM Benefits and Costs</u>

Q. Please explain Staff's issue regarding EIM Benefits and Costs.

A. The first issue presented by Staff is regarding Idaho Power's projected level of benefits to be included in the 2018 APCU.[6]

Q. What is Idaho Power's proposed level of EIM benefits to be included in the 2018 APCU?

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[5] *In the Matter of Idaho Power Company, 2016 Annual Power Supply Expense True-Up*, Docket No. UE 320, Idaho Power/200, Waites/2 (March 24, 2017).

[6] Staff/400, Gibbens/3.

A. Idaho Power proposed to include $81,520 in Oregon-allocated EIM benefits in the 2018 APCU.

Q. How did Idaho Power arrive at this level of forecast EIM benefits?

A. As described in Opening Testimony, Idaho Power proposed to set EIM benefits equal to incremental EIM costs for the first year of participation. The Company's proposal was premised on the uncertainty surrounding the level of EIM benefits the Company expects to achieve in the first year of participation. The Company's proposal also mirrored the treatment granted to PacifiCorp ("PAC") and Portland General Electric Company ("PGE") in their first year of participation in the EIM.

Due to uncertainty, neither PAC nor PGE included a forecast of EIM benefits in their power cost filings for the first year of participation. In PAC's 2015 Transition Adjustment Mechanism ("TAM") filing, PAC stated that, "due to uncertainty surrounding the level of benefits that will be achieved, particularly in the early stages of EIM operation, [PAC] has not included the impact of the EIM in this case."[7] In that case, the Joint Testimony in Support of Stipulation states, "The Settling Parties agree that, at this time, the costs and benefits associated with EIM are difficult to predict with certainty. As an interim approach, the Settling Parties agree that it is reasonable to offset EIM costs and benefits in 2015 NPC."[8] The settlement stipulation was adopted in Order No. 14-331.

In its 2017 Power Cost Update filing, PGE also proposed not to include a forecast of EIM costs or benefits, citing uncertainty surrounding the level of benefits

[7] *In the Matter of PacifiCorp, dba Pacific Power, 2015 Transmission Adjustment Mechanism*, Docket No. UE 287, PAC/100, Dickman/4 (April 1, 2014).

[8] *In the Matter of PacifiCorp, dba Pacific Power, 2015 Transmission Adjustment Mechanism*, Docket No. UE 287, Settling Parties/100, Dickman, Ordonez, Garcia, Jenks & Mullins/Page 8 (August 14, 2014).

that will be achieved.[9] Ultimately, PGE, Staff, and parties agreed to set EIM benefits equal to costs as part of the settlement stipulation approved in Order No. 16-419.

Q. Does Idaho Power believe it is reasonable to use the same methodology as PAC and PGE regarding the forecast of EIM benefits for the first year of participation?

A. Yes. Similar to Idaho Power, both PAC[10] and PGE[11] commissioned Energy + Environmental Economics, Inc. ("E3") to identify potential customer benefits that may be obtained through EIM participation. But, ultimately PAC and PGE requested to set EIM benefits equal to EIM costs for the first year of participation due to uncertainty surrounding the level of benefits that may actually be achieved. Idaho Power believes it should receive the same Commission-approved treatment as PAC and PGE because the level of uncertainty surrounding EIM benefits in the first year of participation is no different for Idaho Power than it was for PAC and PGE.

Q. Please explain Staff's concern regarding the Company's proposed treatment of EIM costs and benefits.

A. In his Opening Testimony, Mr. Gibbens acknowledges that PAC's and PGE's forecasts of net variable power costs included projections of first-year benefits and costs of EIM participation that netted to zero; however, Mr. Gibbens states, "there is a timing difference between Idaho Power and the other utilities that means the potential for harm to customers if Idaho Power over-recovers for EIM costs is greater than it was for PGE and PacifiCorp."[12]

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[9] *In the Matter of Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125)*, Docket No. UE 308, UE 308/PGE/400, Niman – Peschka – Hager/20 (April 1, 2016).

[10] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market*, Docket No. UM 1689, Application at 11 (April 18, 2014).

[11] *In the Matter of Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125)*, Docket No. UE 308, UE 308/PGE/400, Niman – Peschka – Hager/17 (April 1, 2016).

[12] Staff/400. Gibbens/4.

Q. Please elaborate on the "timing difference" that Staff is referring to.

A. Staff explains that the timing of Idaho Power's EIM participation presents two issues. First, Staff is concerned about the potential that the deadband applied to the NPSE true-up amount in Idaho Power's PCAM will absorb net benefits associated with the EIM. Staff expresses concerns that if Idaho Power receives more benefits from EIM participation than it currently projects, Idaho Power has the opportunity to keep excess benefits up to the deadband established by the Commission.

Second, Staff states, "PacifiCorp and PGE joined the EIM in the last quarter of the test year used for their power cost recovery mechanisms. Accordingly, the costs and benefits at issue were less for these two utilities than for Idaho Power. [T]he relative magnitude of the benefits lost to customers would be significantly less for PGE and PacifiCorp customers than it would be for Idaho Power's customers."[13]

Q. What is Idaho Power's response to Staff's reasoning?

A. In general**,** Idaho Power believes that the timing of its participation in the EIM is not a valid reason for receiving different treatment than the other two utilities. The fact that Idaho Power's timing of participation in the EIM aligns with the APCU test year is a coincidence. Regarding Staff's first concern that actual EIM benefits in excess of forecast EIM benefits may be retained by the Company due to the PCAM deadband, the Company points out that the PCAM deadband also prevents Idaho Power from recovering excess NPSE that falls within the deadbands. Since the PCAM was established, on June 1, 2008, the Company has under-recovered approximately $9.0 million in prudently-incurred Oregon-allocated NPSE, and has had to absorb these costs due to the deadbands. It would be unreasonable and unfair to allow the deadbands to prevent recovery of excess NPSE, while at the same time preventing

[13] Staff/400, Gibbens/4-5.

the Company from retaining any benefits related to reduced NPSE in the first year of EIM participation.

Second, the Company does not agree with Staff's statement that, "the costs and benefits at issue were less for these two utilities [PAC and PGE] than for Idaho Power."[14] In fact, the level of EIM costs and benefits included in Idaho Power's 2018 APCU are proportionally less than the costs and benefits at issue in PAC's 2015 TAM, and were only slightly higher than the EIM costs and benefits included in PGE's 2017 Power Cost filing. On an Oregon-allocated basis, EIM benefits and costs included in Idaho Power's 2018 APCU represent 0.44 percent of NPSE ($81,520 / $18,568,852). In PAC's 2015 TAM, on an Oregon-allocated basis, EIM benefits and costs were set at $1,721,044, which represented 0.47 percent of NPSE ($1,721,044 / $369,994,459). In PGE's 2017 Power Cost filing, EIM benefits and costs were set at $1,011,000, which represented 0.26 percent of NPSE ($1,011,000 / $382,900,000).

Q. What level of projected EIM benefits does Staff suggest the Company include in the 2018 APCU?

A. Staff suggests a projected level of EIM benefits of $5.5 million, on a system-wide basis, be included in the 2018 APCU.[15]

Q. How did Staff arrive at the $5.5 million in projected EIM benefits?

A. Staff points to the E3 EIM study, commissioned by Idaho Power, which reports a base case scenario of $4.5 million in estimated EIM benefits that may be achieved by Idaho Power. Staff added $1 million in EIM benefits associated with flexibility reserve savings.

Q. How did Staff arrive at the $1 million flexibility reserve benefit?

[14] Staff/400, Gibbens/5.

[15] Staff/400, Gibbens/4.

A. In his Opening Testimony, Mr. Gibbens explains that Idaho Power does not include flexibility reserve savings in its forecast of EIM benefits, as the other two regulated utility companies include in their EIM-based power cost forecast adjustments.[16] Mr. Gibbens points to PAC's 2018 TAM, Docket No. UE 323, in which PAC included $3.1 million in flexibility reserve benefits in its power cost forecast. Mr. Gibbens also points to PGE's 2017 general rate case, Docket No. UE 319, in which PGE included $1 million in flexibility reserve savings in their forecast of EIM benefits.

Q. Does Idaho Power have concerns with Staff's basis for the $1 million increase in forecast EIM benefits associated with flexibility reserve benefits?

A. Yes. First, Mr. Gibbens suggests that Idaho Power should include flexibility reserve benefits in its NPSE forecast because the other two Oregon utilities do; however, neither of these utilities included flexibility reserve benefits in their power cost forecast adjustments in their first year of participation in the EIM due to uncertainty.

Second, Staff arbitrarily suggests a $1 million increase in EIM benefits based on the amount of flexibility reserve benefits forecast by the other two Oregon utilities. The $1 million estimate is not based on any analysis, studies, or actual data related to Idaho Power. The Company has not started participating in the EIM and has no experience from which to draw any conclusions on benefits that may be achieved due to flexibility reserves. Idaho Power does not believe it is reasonable to include a value for flexibility reserve benefits that have not been measured through a study and defined as benefits nor observed through actual experience.

Q. Does Staff offer a recommendation for the treatment of EIM costs and benefits in light of the Company's uncertainty surrounding expected EIM benefits?

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[16] Staff/400, Gibbens/3-4.

A. Yes. Staff recommends that benefits and non-capital costs for the first year of Idaho Power's participation in the EIM be subject to recovery outside the APCU through deferred accounting and amortization. Furthermore, any potential refund or charge would still be subject to an earnings test, but would not be absorbed in the PCAM's deadband. Staff states that this treatment would account for uncertainty in benefits, but still ensure that customers receive an appropriate share of whatever net benefits (costs) are realized.[17]

Q. What is Idaho Power's response to Staff's recommendation?

A. Idaho Power does not agree with Staff's recommendation to defer EIM-related non-capital costs and benefits for the first year of participation. The Company believes that because EIM benefits are in the form of reduced NPSE, it is not appropriate to remove these benefits, or the costs incurred to achieve reduced NPSE, from the APCU mechanism. The APCU mechanism was implemented to allow Idaho Power the ability to recover NPSE, per Commission Order No. 08-238. Also, as noted previously, the Company does not believe that the PCAM deadbands should be selectively applied to NPSE components.

The Company also believes Staff's recommended approach would be administratively burdensome. In order to defer EIM-related benefits for the first year of participation, the Company would first have to establish separate Oregon jurisdictional sub-accounts for system NPSE because the methodology does not align with the methodology expected to be used for the Company's Idaho jurisdiction. Then, Idaho Power would have to quantify actual EIM benefits and determine which NPSE accounts the benefits are attributed to, such as fuel, purchased power, or surplus sales. Finally, because benefits will actually be flowing through the NPSE accounts, in

[17] Staff/400, Gibbens/6.

order to defer the benefits the Company would have to prepare journal entries to increase (fuel or purchased power) or decrease (surplus sales) the corresponding Oregon jurisdictional NPSE sub-accounts and record the benefits in a Regulatory Liability account.

Q. Does the Company have an alternative recommendation for inclusion of EIM costs and benefits in the APCU?

A. Yes. Idaho Power understands Staff's concern regarding Idaho Power's projected level of EIM benefits. As noted by Staff, Idaho Power commissioned E3 to provide a study of estimated benefits associated with Idaho Power's participation in the EIM. The E3 study estimated base case NPSE savings of $4.5 million on a system-wide basis. Idaho Power would be amenable to including the Oregon jurisdictional share of the E3 estimated benefits, or $210,417, in the 2018 APCU. These benefits would be offset by the Company's Oregon jurisdictional forecast annual revenue requirement related to EIM costs, which includes capital-related costs, of $81,520.

Idaho Power is also open to investigating a methodology for including EIM benefits related to flexibility reserve savings in future APCU filings, once the Company has gained experience in the EIM and has historical data to base such a forecast on.

Q. Does Staff have any other concerns regarding the Company's proposed treatment of EIM costs and benefits?

A. Yes. Staff objects to Idaho Power's inclusion of capital-related costs in the APCU, stating that the APCU is designed for recovery of NPSE, not capital costs. Staff recommends that the Commission reject Idaho Power's proposal to include recovery of and return on EIM capital investments as part of its recovery of NPSE.[18]

Q. What is the Company's position on this issue?

[18] Staff/400, Gibbens/6.

A. Idaho Power agrees with Staff that the APCU is designed for recovery of NPSE; however, Idaho Power incurred incremental capital costs associated with joining the EIM in order to achieve benefits on behalf of customers. And those benefits are in the form of reduced NPSE, which are appropriately reflected in the APCU. Furthermore, the benefits associated with Idaho Power's participation in the EIM will automatically begin flowing to customers upon commencement of participation in the EIM. Idaho Power believes that an interim rate mechanism for cost recovery is necessary to provide for proper matching of costs and benefits in customer rates. The cost/benefit matching proposed by the Company will ensure that the customers who receive the benefits of Idaho Power's participation in the EIM also pay for the costs to participate. Staff's proposed treatment would provide the Company no opportunity to recover its prudently incurred incremental capital-related EIM costs outside of a general rate case. Absent an ability to recover the costs, Idaho Power would suffer negative financial impacts as a direct result of making an investment to lower overall costs for customers.

Q. Does the Company have any other concerns with Staff's objection to Idaho Power's requested recovery of EIM capital-related costs in the APCU?

A. Yes. Staff agreed that PAC and PGE should be authorized to include recovery of EIM capital-related costs (including the return of and on capital investments) in their power cost filings. In PAC's most recent PCAM filing, Staff agreed that PAC should continue to recover its EIM-related costs (including capital-related costs) through the TAM filings. The settlement stipulation in PAC's 2016 PCAM, Docket No. UE 327, which was adopted in Order No. 17-524, states, "PacifiCorp will remove rate of return costs related to its participation in the Energy Imbalance Market from the Company's 2016 and future PCAM filings (PCAM). The costs will remain in PacifiCorp's TAM filings, but will not be subject to true-up in the PCAM."[19] PGE has since filed a general rate case and has included EIM costs and benefits in base rates.

Q. Does the Company have an alternative recommendation regarding recovery of EIM capital costs?

A. Yes. As stated previously, costs associated with the EIM were incurred solely to achieve benefits on behalf of customers. For this reason, the Company believes it should be provided an opportunity to recover these costs. In recognition of Staff's position on the truing-up of capital-related costs, Idaho Power is willing to remove EIM capital-related costs from true-up in the PCAM, pending a final decision in Oregon Docket No. UM 1909, Investigation of the Scope of the Commission's Authority to Defer Capital Costs. The Company believes this is a fair approach and is in line with the treatment granted for PAC.

Rate Spread

Q. Please explain Staff's issue regarding the allocation of NPSE.

A. In his Opening Testimony, Mr. Kaufman explains that in the 2017 APCU parties stipulated that in future APCU filings Idaho Power would use the Staff-proposed "total cost methodology" to allocate power costs between Idaho Power's Idaho and Oregon jurisdictions and among rate classes in Oregon. Staff has concerns with Idaho Power's application of the total cost method in the 2018 APCU stating, "Staff has yet to determine whether Idaho Power correctly applied the total cost method."[20]

Q. What is the total cost method proposed by Staff?

A. Under Staff's proposed methodology, Idaho Power is to reset and allocate total NPSE each year rather than making an incremental change to rates for NPSE one year to

[19] *In the Matter of PacifiCorp, dba Pacific Power, 2016 Power Cost Adjustment Mechanism*, Docket No. UE 327, Order No. 17-524, Appendix A at 3 (December 27, 2017).

[20] Staff/200, Kaufman 4, lines 8-9.

the next. More, specifically, Idaho Power is to calculate the Oregon jurisdictional share of the APCU revenue requirement by multiplying the system NPSE total per-unit cost by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April – March test period. Then under Staff's proposed methodology, Idaho Power is to calculate rates by allocating total power costs to service schedules rather than incremental costs.

Q. Did Idaho Power use Staff's proposed methodology for calculating rates for the 2018 APCU?

A. Idaho Power did reset and calculate the Oregon jurisdictional share of total NPSE for the 2018 APCU, rather than calculating the Oregon jurisdictional share of incremental NPSE as was done in prior years; however, Idaho Power did not calculate customer rates by allocating total Oregon jurisdictional NPSE. Instead Idaho Power calculated customer rates by allocating the incremental Oregon jurisdictional NPSE.

Q. Please walk through the specific calculations Idaho Power used in the 2018 APCU.

A. Per the settlement stipulation in the 2017 APCU, Idaho Power reset and calculated the Oregon jurisdictional share of total NPSE by multiplying the system NPSE total per-unit cost of $26.54 per MWh by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April 2018 – March 2019 test period of 699,655.310 MWh, resulting in an Oregon jurisdictional share of NPSE of $18,568,852 ($26.54 x 699,533.310 MWh = $18,568,852).

Idaho Power then calculated the incremental Oregon jurisdictional NPSE by comparing the 2018 October Update Oregon jurisdictional share of total NPSE of $18,568,852 to the NPSE recovery under current approved rates from the 2017 October Update of $18,208,743, resulting in an APCU revenue requirement of $360,109 ($18,568,852 - $18,208,743 = $360,109). Finally, the Company allocated the $0.36 million incremental Oregon jurisdictional NPSE to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the test period of June 2018 – May 2019.

Q. Why did Idaho Power chose to calculate customer rates by allocating the incremental Oregon jurisdictional NPSE of $0.36 million rather than the total Oregon jurisdictional NPSE of $18.6 million?

A. When Idaho Power was preparing the initial October Update filing, it used Staff's preferred total cost methodology for allocating NPSE; however, the results were very concerning to the Company. Because Staff's proposed methodology unwinds all previously approved incremental rate changes among customer classes and resets total NPSE allocated to each class, it resulted in relatively large rate changes for each customer class. Examples of these large rate changes included a 4.16 percent decrease for residential customers and a 4.69 percent increase for industrial customers, as compared to a 0.52 percent increase for residential customers and a 0.83 percent increase for industrial customers as proposed in the Company's 2018 APCU October Update filing.

Q. What steps did Idaho Power take to address these impacts in preparing the 2018 APCU October Update?

A. Idaho Power held a telephonic conference call with Staff on October 24, 2017, to discuss the revenue spread methodology and express the Company's concerns. Based on that call, Staff and the Company agreed that it would be unreasonable to file the 2018 APCU as previously detailed. Staff indicated support for the Company's recommendation to file the 2018 APCU by allocating the incremental Oregon jurisdictional NPSE among customer classes and noted that it was the proper solution for the initial filing. Staff also mentioned that while the rate spread methodology to be filed by the Company in the initial October Update filing was the proper solution, that it may not be the final solution that Staff supports following the conclusion of the 2018 APCU docket.

Q. What is Staff's recommendation for the 2018 APCU rate spread?

A. In his Opening Testimony, Mr. Kaufman states that Staff has yet to determine whether Idaho Power correctly applied the total cost method. Staff will continue its investigation of rates applied in previous years to determine if the 2018 APCU rates were appropriately calculated.

Q. Does Idaho Power support Mr. Kaufman's recommendation?

A. Idaho Power believes that it correctly calculated the 2018 APCU rates; however, the Company will continue to work with Staff in its investigation of the rate spread methodology to address concerns and provide understanding.

<u>Bridger Coal Company</u>

Q. Please explain the Company's understanding of the issue presented by Staff regarding the BCC coal costs.

A. The second issue, raised by Mr. Kaufman in his Opening Testimony, is related to the inclusion of depreciation expense in BCC coal costs associated with BCC plant that has been added since Idaho Power's last rate case.

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

A. Mr. Kaufman recommends that depreciation costs associated with BCC plant added after Idaho Power's last rate case be excluded from rates. Mr. Kaufman asserts that BCC has annual depreciation expense of **[Begin Protected Information]** [redacted] **[End Protected Information]** associated with post rate case plant additions and that Idaho Power's share of this is **[Begin Protected Information]** [redacted] **[End Protected Information]**. Mr. Kaufman suggests a reduction of **[Begin**

Protected Information] [redacted] **[End Protected Information]** to system NPSE included in the 2018 APCU.[21]

Q. Do you agree with Mr. Kaufman's conclusion and subsequent recommendation?

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

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

A. Idaho Power owns 100 percent of IERCo, which has a one-third joint venture interest in BCC. Idaho Power accounts for IERCo as an equity method investment. Separate records and accounts for IERCO are maintained and the operations of IERCO as a joint venturer in BCC are subject to regulatory review and scrutiny together with those of Idaho Power during general rate cases.

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

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

[21] Staff/200, Kaufman/8, lines 6-11.

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

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

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

> The application should be granted. The coal sales agreements in question will not harm [Idaho Power's] customers because the agreements provide to [Idaho Power] a reliable source of low-cost coal for operation of the Jim Bridger plant.
>
> The transfer price for the coal which is provided by Bridger to [Idaho Power] shall be billed at actual cost . . . . The Commission concludes that the agreement is fair and reasonable and not contrary to the public interest.
>
> [Idaho Power's] contract with Bridger has and shall continue to be recognized for rate-making purposes. Expenditures made should be charged to accounts in the manner directed by the Federal Energy Regulatory Commission regulations and by the Commission's rules.[22]

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

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[22] *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).

A. No. BCC is a non-utility entity, and therefore, its assets are treated differently for ratemaking purposes than the Company's standard utility assets. Under traditional ratemaking for standard utility assets, the Company invests in rate base on behalf of customers, then requests approval to collect through rates the cost of its investment and a fair rate of return through a ratemaking proceeding at the Commission. Alternatively, BCC is a non-utility entity, and its assets have been subject to treatment that differs from that of standard utility assets. Because BCC costs (including depreciation expense associated with assets in service at the mine) reflect the cost of procuring fuel for the Bridger Plant, they have been recognized by the 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, whether assets have been added, retired, or sold. This ensures that customer rates are reflective of the current cost of procuring fuel for the Bridger Plant.

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

A. Yes. The Commission has recognized and approved BCC costs as fuel expense in Docket Nos. UE 92, UE 167, UE 203, UE 213, UE 214, UE 222, and the Company's last general rate case, UE 233. Since the Company's last general rate case, the Commission has recognized and approved BCC costs, including depreciation expense associated with assets in service at the mine, in Docket Nos. UE 242, UE 257, UE 279, UE 293, UE 301, and UE 314.

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

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

Additionally, updating BCC costs to reflect depreciable assets currently in service can serve as an immediate benefit to customers in the event that mine assets are sold. A recent example of this occurred in Docket No. UP 334, in which the disposition of BCC assets resulted in lower overall fuel costs to customers. In Docket No. UP 334, the Company requested an order authorizing the sale by BCC of a Page 732E Dragline ("Dragline") and associated parts. In the Application, Idaho Power explained that the Dragline, which is a large, earth moving machine, was put into service in 1974 for surface mining operations. The Dragline was taken out of service in 1998 because it was too small to continue to operate economically at the BCC surface mine. BCC attempted to negotiate the sale of the Dragline to various parties over time, and eventually sold the asset in 2016 at approximately $190,000 above net book value. As pointed out in Staff's Report:

> The proceeds will flow through BCC's income statement and be reflected in the cost of coal burned at the Jim Bridger generating plant, reducing net power costs. Fuel costs are updated annually through the Company's fuel cost adjustment mechanism; *therefore, lower fuel costs for the Company result in lower costs to customers, regardless of the timing of general rate cases*.[23]

[23] *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).

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

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

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

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

Q. Please explain Staff's issue regarding the depreciable lives for BCC plant.

[24] *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).

A. The third issue, raised by Mr. Kaufman in his Opening Testimony, relates to depreciation rates for BCC plant. In his testimony, Mr. Kaufman cites concerns with the depreciable lives for BCC assets, specifically for freight and passenger trucks, and suggests that a review of depreciation expense for all BCC plant is needed to determine whether it is reasonable.[25]

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

A. Mr. Kaufman recommends the Company include BCC assets in subsequent depreciation studies.[26]

Q. What is Idaho Power's position on this recommendation?

A. Because BCC is a non-utility entity, it does not record Property Plant & Equipment ("PP&E") in the electric plant accounts defined in the Federal Energy Regulatory Commission's Code of Federal Regulations ("CFR"). Therefore, independent depreciation studies typically used to establish and update service lives and depreciation rates for utility ratemaking purposes are not conducted for BCC assets.

Q. If BCC does not record PP&E in accordance with the CFR, how does BCC classify assets for depreciation purposes?

A. PP&E investment at BCC consists of three major asset groups: Surface Mine assets, Underground Mine assets, and Administrative assets. Administrative assets include assets that are common to both the Surface and Underground operations. Upon acquisition, each asset is assigned to a fleet of similar assets with a service life unique to that fleet.

Each of the three major asset groups are further segmented into two types of assets. The first type includes life of mine assets, which are assets that will be used and useful from the time they are declared in-service until the mine ceases operation,

[25] Staff/200, Kaufman/8, lines 12-16 and 9, lines 2-4.

[26] Staff/200, Kaufman/9, line 9.

such as buildings. The second type includes assets that are subject to deterioration through usage and must be replaced periodically. Generally, these assets are unique to their mode of coal extraction (surface/underground) and are not shared in the normal course of operations.

Capital assets in all three major asset groups are depreciated using the straight-line method wherein each individual asset is tracked from acquisition to retirement. Assets that exceed their assigned depreciable service lives remain in PP&E at a net book value of zero until their reliable and useful life expires, at which point they are retired and disposed of. Any gain or loss on disposition of assets is included in the price of coal BCC charges to Idaho Power and PAC, as described previously in my testimony.

Q. How are the depreciable service lives for BCC assets determined?

A. The depreciable service lives for mine assets are based on manufacturer and/or industry standards, historical operating data, and professional judgment of key mine personnel; however, there are two types of assets with unique depreciation methodologies. The first includes bonus payments for the acquisition of coal leases, which are amortized on a tonnage basis as coal is extracted. The second includes longwall shields, which are depreciated based on units of production.

Q. Does Idaho Power have a recommendation for Staff's concern regarding the depreciable lives of BCC assets?

A. Yes. Although utility plant depreciation studies are not conducted for BCC plant, Idaho Power is agreeable to working with Staff to provide documentation to support the depreciable lives for BCC plant.

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

A. With the exception of the Bridger fueling plan, all of the issues or concerns identified in Staff's Opening Testimony have been addressed and reasonably explained. In his Reply Testimony, Mr. Harvey will address Staff's concerns related to the near-term and long-term fueling plan for Bridger.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

CONFIDENTIAL

Exhibit Accompanying Reply Testimony of Nicole A. Blackwell

2016 APCU October Update PURPA Forecast Versus Actual PURPA
Expense and Generation for April 2016 – March 2017

March 1, 2018

EXHIBIT 201 IS CONFIDENTIAL PER PROTECTIVE ORDER 17-443 AND WILL BE PROVIDED SEPARATELY VIA CD

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 333

IN THE MATTER OF IDAHO POWER COMPANY'S 2018 ANNUAL POWER COST UPDATE	)
OCTOBER UPDATE	)

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

TOM HARVEY

March 1, 2018

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Tom Harvey and my business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the General Manager of Power Supply, Planning and Operations in the Power Supply Department.

Q. Please describe your educational background.

A. I have a Bachelor of Business Administration in business management from Boise State University. I also attended the University of Idaho's Utility Executive Course in 2011.

Q. Please describe your work experience with Idaho Power.

A. I was hired by Idaho Power in July 1980 to work in the Plant Accounting Department. I continued working in the accounting area through 1985. From 1985 through 2009, I was the Fuels Management Coordinator and then was promoted to the Joint Projects Manager. In April 2015, I was promoted to Resource Planning and Operations Director. In January 2018, I was promoted to my current position, General Manager of Power Supply, Planning and Operations Power Supply. My current responsibilities include supervision over Idaho Power's jointly-owned coal assets, integrated resource planning, load serving operations, and merchant activities.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to respond to issues raised by the Public Utility Commission of Oregon ("Commission") Staff ("Staff") witness Mr. Lance Kaufman, in his February 12, 2018, Opening Testimony. Specifically, I will address Mr. Kaufman's concerns related to the near-term and long-term fueling plan for the Jim Bridger coal-fired plant ("Bridger").

Q. Please explain Staff's issue regarding the Bridger Fuel Plan.

A. In his Opening Testimony, Mr. Kaufman expresses concerns related to the short-term and long-term fueling plans for Bridger. Mr. Kaufman notes the following concerns regarding the fueling plan process:

(1) Idaho Power did not consider an important option for the near-term coal supply.

(2) Long-term options did not inform the selection of the near-term plan.

(3) Idaho Power's long-term plan does not appear to consider the differential planning requirements that SB 1547 places on Idaho Power and PacifiCorp ("PAC").

(4) Idaho Power is engaging in a fixed volume coal contract without evaluating risks associated with having a fixed volume contract.

Q. Please elaborate on Mr. Kaufman's first concern.

A. Together, Idaho Power and PAC evaluated five potential near-term fueling options from the Black Butte Mine ("Black Butte") for Bridger. The five options, Options A – E, contained varying coal volumes, pricing, and terms. On January 11, 2018, PAC presented the determination of the least-cost, least-risk option, Option A, selected by PAC and Idaho Power to meet near-term fueling needs at Bridger. The presentation is included as Protected Information Exhibit 301.

In his Opening Testimony, Mr. Kaufman states that Staff believes Option B is potentially the least-cost option based on confidential information that was provided to Staff outside of the Annual Power Cost Update docket. Mr. Kaufman states, "Staff will provide further detail on this determination once the confidential information is part of this docket."[1]

Q. Does Idaho Power understand why Staff believes Option B is "potentially the least-cost option"?

[1] Staff/200, Kaufman/11, lines 14-15.

A. No. At this time Idaho Power does not understand why Staff believes Option B is potentially the least-cost option. Staff has yet to provide any analysis or sound basis to support its claim. The Company issued discovery to obtain Staff's analysis to support the assumption that Option B is potentially the least-cost option. Idaho Power did not have Staff's response prior to filing Reply Testimony, and therefore cannot fully address Staff's issue. However, the Company will continue to work towards understanding and addressing Staff's assumption that Option B is the least-cost option.

Q. Please elaborate on Mr. Kaufman's second concern.

A. Mr. Kaufman asserts that long-term options did not inform the selection of the near-term fuel plan. Mr. Kaufman's assertion is inaccurate and is not supported by any evidence. Several variables were considered in selecting the near-term fuel plan, including, but not limited to, future contracts with Black Butte, Bridger Coal Company ("BCC") existing reserves, and operational flexibility, all of which were reviewed from both a near-term and long-term perspective of providing the least-cost, least-risk fuel supply to Bridger.

Idaho Power agrees with Mr. Kaufman's statement that long-term options should inform the selection of the near-term fuel supply. As such, Idaho Power and PAC have been developing the Bridger long-term fuel plan in conjunction with near-term fuel plan negotiations with Black Butte. The Bridger long-term fuel plan is presently being finalized and will be filed with the Commission in March 2018. Deliveries from the new contract with Black Butte will begin in May 2018.

Q. Please elaborate on Mr. Kaufman's third concern.

A. Mr. Kaufman states that Idaho Power and PAC may not be subject to the same SB 1547 planning requirements and as such, "Idaho Power should consider how it will navigate different planning needs when PacifiCorp begins to plan in compliance with SB 1547."[2]

Q. What is Idaho Power's response to Staff's third concern?

A. It is the Company's understanding that the SB 1547 provision on the elimination of coal from electricity supply by 2030 is not applicable to Idaho Power. However, as Idaho Power and PAC are joint owners in Bridger, the Company will work with PAC to determine the best course of action in terms of navigating SB 1547 planning requirements related to the plant, as those concerns come into play. Nevertheless, this issue is outside the scope of this docket, which relates to net power supply expense for April 2018 – March 2019.

Q. Please elaborate on Mr. Kaufman's fourth concern.

A. Mr. Kaufman claims that Idaho Power is engaging in a fixed volume coal contract without evaluating risks associated with having a fixed volume contract. More specifically, Staff notes that PAC's power cost model does not allow for economic shutdowns of Bridger, whereas Idaho Power's model does. Consequently, Mr. Kaufman believes that the selection of the high fixed volume coal contract with Black Butte is based on PAC's model, which "likely overestimates the future coal burn at Jim Bridger due to the fact that economic shutdowns were not incorporated."[3]

Q. What is Idaho Power's response to Staff's fourth concern?

A. Idaho Power's understanding of Staff's fourth concern is that due to Staff's belief that PAC is overestimating future coal burn at Bridger, Black Butte Option A was selected as it was the highest volume contract option. And that Idaho Power did not evaluate

[2] Staff/200, Kaufman/12, lines 5-6.

[3] Staff/200, Kaufman/12, lines 18-20.

the risks associated with selecting the highest volume contract option. Again, Staff's assertion is inaccurate and is not supported by any evidence.

The coal supply provided through Black Butte Option A is not split based on the 1/3, 2/3 ownership shares of Idaho Power and PAC, respectively. Idaho Power estimated its needed supply of Black Butte coal based on the Company's forecasted generation at Bridger. PAC also estimated its need supply of Black Butte coal based on its forecasted coal burn at Bridger. Together these two forecasts determined the total coal supply needed from Black Butte to meet the separate needs of Idaho Power and PAC at Bridger.

Although Idaho Power has no reason to believe that PAC is overestimating its forecasted coal burn, it is not the Company's place to challenge PAC's forecast. Regardless, PAC's forecasted coal burn does not impact Idaho Power's forecasted generation and its resulting share of the contracted Black Butte coal supply. While a change in PAC's forecasted coal burn may have impacted which Black Butte option was selected, this point is irrelevant because Idaho Power is only purchasing the amount of coal needed for its forecast generation, not a 1/3 share of the total contracted volume. Moreover, under Option A Idaho Power is achieving favorable pricing as a result of the higher total coal volumes under contract.

Additionally, Mr. Kaufman approaches the selection of the near-term coal contract with Black Butte as though Idaho Power and PAC would select different Black Butte fueling options. Although Idaho Power and PAC do not split third-party coal purchases on a 1/3, 2/3 basis, it still makes sense from an economic perspective to address Bridger fueling options under a holistic approach that provides for least-cost, least-risk supply for both partners. In the event that Idaho Power and PAC negotiate separately with Black Butte and execute contracts individually, pricing would be less favorable for both Idaho Power and PAC. As discussed in the January 11, 2018, Bridger fueling plan workshop, pricing is more favorable on higher volume and longer term contracts. In order to achieve the best pricing possible, it was in the best interest of the Company's and PAC's customers to negotiate a joint coal contract. Idaho Power believes that it could be more risky for the Company to select a lower volume coal contract at a higher price based on Staff's assumption that PAC's forecasted burn at Bridger may be overestimated.

Q. What is Mr. Kaufman's recommendation regarding the Bridger Fuel Plan?

A. Mr. Kaufman recommends that the Commission direct Idaho Power to develop a mine plan consistent with Option B.

Q. Does Idaho Power agree with Staff's recommendation?

A. No. Idaho Power and PAC reviewed multiple scenarios for both near-term and long-term fueling of Bridger. As presented in the January 11, 2018, workshop, which is provided as Protected Information Exhibit 301, PAC and Idaho Power determined Option A to be the least-cost, least-risk near-term fuel supply option for Bridger, based on a BCC mine plan that will be presented to the Commission in March 2018.

By suggesting that the Commission direct Idaho Power to develop a mine plan consistent with Option B, the Company believes that Mr. Kaufman is attempting to build in more precision than is reasonable when evaluating a 20-year fuel plan. In evaluating the fuel supply for Bridger, it is necessary to balance both near-term and long-term needs, costs, and risks. It is not feasible to ensure that every year over the 20-year period is least-cost. Rather, the determination of the least-cost, least-risk fuel supply is based on a comprehensive, long-term viewpoint.

It appears as though Mr. Kaufman may be looking at one year of costs in isolation and determining that an alternative mine plan is necessary based on that review. Instead the 20-year present value revenue requirement ("PVRR") should be considered. Furthermore, in looking at the 20-year PVRR, it is expected that there may be higher costs in certain years, but that over the long-term, the least-cost option is presented. Idaho Power encourages Mr. Kaufman to review the Bridger long-term fueling plan analysis, which will be presented in March 2018, before suggesting that Idaho Power develop another mine plan.

Q. Have you responded to all of the concerns regarding the Bridger fueling plan presented by Staff in Opening Testimony?

A. Yes. All of Staff's concerns related to the Bridger fueling plan have been addressed and reasonably explained.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

Idaho Power/301
Witness: Tom Harvey

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

CONFIDENTIAL

Exhibit Accompanying Testimony of Tom Harvey

Long-Term Fueling Plan Workshop Presentation dated January 11, 2018

March 1, 2018

EXHIBIT 301 IS CONFIDENTIAL PER PROTECTIVE ORDER 17-443 AND WILL BE PROVIDED SEPARATELY

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the confidential pages of this foregoing document in Docket UE 333 on the following named person(s) on the date indicated below by US mail addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: March 1, 2018

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