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March 3, 2020

VIA ELECTRONIC FILING AND U.S. MAIL

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-1088

Re: UE 366 – Idaho Power Company's 2020 Annual Power Cost Update.

Attention Filing Center:

Attached for filing in the above-referenced docket is a copy of Idaho Power Company's Reply Testimony of Nicole A. Blackwell (Idaho Power/200-205). Confidential copies of exhibits will be sent via U.S. Mail to the Filing Center and parties who have signed the Protective Order (Order No. 19-379).

Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till
Paralegal

Attachments

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 366

IN THE MATTER OF IDAHO POWER COMPANY'S 2020 ANNUAL POWER COST UPDATE	)
OCTOBER UPDATE	)

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

NICOLE A. BLACKWELL

March 3, 2020

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 Witnesses Ms. Moya Enright, Mr. Scott Gibbens, Ms. Sabrinna Soldavini, and Ms. Kathy Zarate, in Staff's February 4, 2020, Opening Testimony.

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 four issues raised by Staff in Opening Testimony:

1. Forecast Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses
2. Forecast of Energy Imbalance Market ("EIM") benefits
3. Forecast of Oil, Plant Handling, Administrative and General ("OHAG") expenses at the North Valmy coal-fired plant ("Valmy")
4. 2020 operations at the Boardman coal-fired plant ("Boardman")

PURPA Forecast

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

A. Staff states that over the 2015 – 2018 time period, Idaho Power has overestimated PURPA expense by an average of 19 percent.[1] Staff also notes that Idaho Power has not made a change in approach of estimating PURPA costs.

Q. Has Staff proposed an adjustment to the level of PURPA expense included in the 2020 APCU?

[1] Staff/400, Zarate/7, lines 7-8.

A. Yes. Staff is proposing a $29.1 million decrease in system-level PURPA expense to be included in the 2020 APCU. The adjustment reflects a 13 percent decrease in the Company's forecast PURPA expense based on Staff's determination of a 13 percent overestimation in forecast versus actual PURPA expense for the most recent APCU test year (April 2018 – March 2019).

Q. Did the Company confirm Staff's quantification of the difference between forecast and actual PURPA expense?

A. Yes. Idaho Power reviewed Staff's quantification of the difference between forecast and actual PURPA expense, which was based on data provided by Idaho Power in discovery. However, upon further review, the Company determined that the historical PURPA expense provided in discovery was not re-priced whereas the forecast PURPA expense was. As a result, the data did not support an apples-to-apples comparison, which is the primary driver for the discrepancies in forecast versus actual PURPA expense identified by Staff.

Q. Please explain the Company's reference to "re-priced" PURPA expense.

A. Many of Idaho Power's PURPA contracts have payment provisions that require the Company to provide levelized monthly payments over the length of the contract. However, per Commission Order No. 85-010, Idaho Power is required to re-price PURPA expense to reflect a non-levelized payment stream in rates, rather than the levelized payment stream actually paid on those PURPA contracts. The non-levelized method provides benefits in the early years of the contract by reflecting lower expenses in rates than the actual levelized contract expenses. As time passes, the non-levelized amount included in rates will exceed the actual levelized payments made to the projects.

In compliance with Order No. 85-010, the Company's forecast of PURPA expense included in the APCU is appropriately re-priced to reflect the non-levelized payment stream. In response to Staff's discovery, the Company provided actual PURPA expense, or the actual payments made to PURPA projects, for the 2015 – 2018 APCU test years, and did not provide the re-priced actual PURPA expense. As a result, Staff was comparing forecast re-priced PURPA expense to actual non-re-priced PURPA expense.

Q. Has Idaho Power since provided the re-priced actual information?

A. Yes. Idaho Power provided a supplemental response to Staff's Data Request No. 24 on February 12, 2020, which includes forecast PURPA expense and actual PURPA expense for the 2015 – 2018 APCU test years, both of which have been re-priced to reflect the non-levelized payment stream. The supplemental response to Staff's Data Request No. 24 is provided in Exhibit 201 and the confidential attachment to the supplement response is provided in Confidential Exhibit 202.

Q. Based on the re-priced actual expense, what are the deviations in forecast and actual PURPA expense for 2015 – 2018?

A. Using re-priced actual PURPA expense, the deviations in re-priced forecast PURPA expense and re-priced actual PURPA expense are 7.5 percent, 16.6 percent, 4.4 percent, and 0.6 percent for the 2015 – 2018 APCU test years, respectively. This is compared to deviations in re-priced forecast PURPA expense and non-re-priced actual PURPA expense identified by Staff of 19.4 percent, 28.1 percent, 16.8 percent, and 13 percent for the 2015 – 2018 APCU test years, respectively.

Q. Does the Company believe the deviations in forecast versus actual PURPA expense are reasonable?

A. Yes. The deviations in forecast versus actual PURPA expense for the 2015, 2017, and 2018 APCU test years ranged from .06 percent to 7.5 percent, while the largest deviation of 16.6 percent occurred in the 2016 APCU year. However, as pointed out in the Company's testimony in the 2016 APCU October Update, the PURPA forecast in that year 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 fourteen 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. 52, and provided as Exhibit 203, 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. 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 PURPA 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.

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 Company requests the expected operation date. However, in the event that the project changes the scheduled operation date, unless the project informs Idaho Power, the Company has no way to determine whether the expected operation date is realistic or not. 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. Did the Company make any adjustments to its PURPA forecast methodology to account for the uncertainties surrounding new projects?

A. Yes. In the 2018 APCU, Docket No. UE 333, the Company agreed to a Staff proposal to implement a Contract Delay Rate ("CDR") to the PURPA forecast included in the March Forecast of the APCU. This adjustment is intended to address the uncertainties surrounding scheduled operation date and actual operation date for new PURPA projects and the potential impacts on net power supply expense ("NPSE"). The CDR is based on the three-year average of differences in scheduled operation dates and actual operation dates of historical PURPA projects. This three-year average CDR is then applied to any new PURPA project expected to come online during the forecast test period for the March Forecast of the APCU.[2]

Q. Based on the new information provided in the Company's supplemental response to Staff's Data Request No. 24 and the 2018 implementation of Staff's proposed CDR methodology, is there still a need for Staff's proposed adjustment to PURPA expenses in this case?

A. No. Staff's recommended adjustment to the PURPA forecast was initially based on a 13 percent deviation in re-priced forecast PURPA expense and actual PURPA expense for the 2018 APCU test year. Through the Company's supplemental

[2] *In the Matter of Idaho Power Company, 2018 Annual Power Cost Update*, Docket No. UE 333, Order No. 18-170, Appendix A, p. 8 (May 21, 2018).

response to Staff's Data Request No. 24, Idaho Power has provided the information to appropriately calculate the difference in re-priced forecast PURPA expense and re-priced actual PURPA expense. Based on this information, the deviation in re-priced forecast PURPA expense and re-priced actual PURPA expense is less than 1 percent. This supplemental information eliminates the need for Staff's recommended $29.1 million downward adjustment to the PURPA forecast included in the 2020 October Update. Furthermore, Staff's concern surrounding the forecasting of generation and expense for new PURPA projects is addressed through the CDR provision of the APCU.

Forecast of EIM Benefits

Q. What is Idaho Power's proposed level of EIM benefits to be included in the 2020 APCU?

A. Idaho Power proposed to include $15.6 million in system EIM benefits as an offset to NPSE in the 2020 October Update. On an Oregon allocated basis, the EIM benefits to be included in the 2020 October Update total $724,599.

Q. How does this compare to the level of EIM benefits included in last year's October Update?

A. The settled 2019 October Update system EIM benefit was $15.1 million, or $699,431 on an Oregon allocated basis.

Q. How did the Company determine the level of EIM benefits to be included in the 2020 October Update?

A. As described in Opening Testimony, Idaho Power's proposed level of EIM benefits to be included in the 2020 October Update utilizes the California Independent System Operator ("CAISO") report of EIM benefits, for October 2018 through September 2019, as a starting point, and then accounts for necessary adjustments to quantify ongoing cost savings benefits specific to Idaho Power's participation in the EIM. These adjustments include a modification to the CAISO methodology as it pertains to the hydro pricing cost structure, and an adjustment for third-party load included in the Company's balancing area.[3]

Q. Please explain Staff's concern regarding the Company's proposed level of EIM benefits.

A. In Opening Testimony, Staff expresses concerns with the Company's EIM benefits model, specifically the Company's adjustment to the hydro pricing cost structure. Staff asserts that the model does not provide an optimal forecast of the Company's EIM benefits and that it has concerns with the use of a zero-cost hydro bid value.[4]

Q. Please describe the modification Idaho Power made to the CAISO EIM benefit methodology as it pertains to the hydro pricing cost structure.

A. As more fully explained in Opening Testimony, to reflect the correct economic value of the hydro dispatches in CAISO's EIM benefit calculation, Idaho Power made a two-part adjustment to the cost structure of the Company's hydro resources. First, all hydro dispatch costs are held constant by applying a zero-cost. This satisfies a correction to CAISO's EIM counterfactual ("CF") costs as there should not be any costs associated with Idaho Power's dispatching up and down of its hydro resources to meet its own load imbalances.

Holding the dispatch costs constant by applying a zero-cost also satisfies a correction to the EIM dispatch costs. The EIM is not a capacity market. Therefore, in a hydro system with limited ability to store water long term, the majority of EIM imports (or the dispatching down and storage of the water) will have matching exports over a given time period (that water will be exported soon thereafter). When EIM hydro imports have matching exports over a measured period, in the case of Idaho Power's

[3] Idaho Power/100, Blackwell/14-20.

[4] Staff/100, Enright/15, lines 17-20.

analysis on a daily basis, dispatch costs should be held constant by replacing all tier prices with a zero cost. In this scenario, the actual benefit is the difference between the EIM import and export price. If the EIM dispatch cost is not held constant over the measured period, it results in an inaccurate benefit. However, when hydro imports do not equal exports over the measured period, it is necessary to value, or assign a cost to, the net import / exports to the market; this is the second adjustment Idaho Power made to the hydro cost structure.

When imports exceed exports during the measured period, using a zero-cost value will underestimate benefits because it does not properly account for the value of imported energy that served load (rather than hydro) and provided a benefit to the Company's customers. Conversely, when exports exceed imports during the measured period, the zero-cost value will inflate benefits because there are no costs assigned to the water that was moved into the market. In either scenario, the net imports / exports for the hydro resources will show a benefit at the EIM Locational Marginal Price because there are no costs associated with the hydro dispatches.

As a result, Idaho Power made a second adjustment to the EIM benefit calculation by assigning a value to the hydro net imports / exports for each day based on the average daily sale price in the bilateral market. Applying a market price to the net hydro import / export position allows the Company to properly account for the cost of hydro that was imported or exported into the EIM.

Q. Given Staff's issue with Idaho Power's adjustment to the hydro cost structure, do they propose an alternate methodology for determining forecast EIM benefits?

A. Staff proposes to use a modified version of the Company's methodology and recommends two alterations to the hydro net import / export adjustment. First, Staff proposes use of a Mid-Columbia mid-market electricity price to assign a value to the hydro net imports / exports rather than a bilateral sales price. Second, Staff proposes that the Company's hydro net import / export adjustment be assessed on an hourly basis rather than a daily basis.

Q. Does the Company agree with Staff's modifications to the Company's EIM benefit methodology?

A. Yes. Idaho Power agrees with Staff's proposed modifications to the Company's EIM benefit methodology. Conducting the hydro net import / export analysis on an hourly basis, as well as using a Mid-Columbia mid-market electricity price will provide more accuracy in determining the Company's EIM benefits forecast. The Company intends to implement these methodology changes into the EIM benefits forecast for the 2020 APCU March Forecast filing, which will include an update to the amounts quantified in the October Update.

Q. How does Staff's proposed adjustment impact the Company's forecast of EIM benefits?

A. Staff's proposed adjustments to the Company's EIM benefit methodology results in a \$0.1 million decrease in forecast EIM benefits included in the October Update. The forecast of EIM benefits will be updated with the March Forecast filing and will incorporate the latest EIM data from CAISO.

Q. Does Staff propose any other adjustments to Idaho Power's forecast of EIM benefits?

A. Yes. Staff recommends "use of a growth factor in forecasted EIM benefits, reflecting the consistent annual growth in benefits experienced by all EIM participants."[5] Specifically, Staff recommends applying a 22 percent growth factor to the Company's

[5] Staff/100, Enright/18, lines 8-9.

forecast of EIM benefits, which results in a $5.1 million increase to Idaho Power's forecast of EIM benefits.

Q. Does the Company agree with Staff's claim that all EIM participants have experienced consistent annual growth in benefits?

A. No. Although some EIM participants have experienced growth in EIM benefits, this is not the case for all participants. Based on Staff's workpapers, which is supported by the CAISO Western EIM Quarterly Benefits Reports, both CAISO and NV Energy experienced year-over-year[6] reductions in EIM benefits of 32 percent and 22 percent, respectively. Updating Staff's analysis using CAISO's Fourth Quarter 2019 Western EIM Benefits Report, which was unavailable at the time of Staff's Opening Testimony, CAISO, NV Energy, and PacifiCorp ("PAC") experienced year-over-year[7] reductions in EIM benefits of 34 percent, 10 percent, and 3 percent, respectively. This updated data demonstrates that half of the EIM participants experienced year-over-year growth in EIM benefits while the other half experienced a year-over-year reduction in EIM benefits. Idaho Power does not agree with Staff's position that a growth factor is appropriate given consistent annual growth in benefits experience by all EIM participants. The analysis does not support this correlation.

Q. How did Staff arrive at the 22 percent growth factor for forecast EIM benefits?

A. Staff's 22 percent growth factor is based on the average of year-over-year changes in EIM benefits for CAISO, PAC, NV Energy, Arizona Public Service Company ("APS"), Puget Sound Energy ("PSE"), and Portland General Electric ("PGE"), which includes all entities that had been participating in the EIM for two full years as of third-quarter-end 2019.

Q. Does Idaho Power believe Staff's growth factor methodology is appropriate?

[6] Year Ending Q3 2018 to Year Ending Q3 2019.

[7] Year Ending 2018 to Year Ending 2019.

A. No. Idaho Power has three concerns with Staff's proposed growth factor methodology. First, the methodology disregards the significant volatility in EIM benefits and the potential impact it could have on the Company's EIM benefits forecast. Not only are EIM benefits volatile from one participant to another, but also on a quarter-over-quarter basis for each participant. For example, Staff's determination of the 22 percent growth factor, as described above, was based on year-over-year changes in EIM benefits for six participating entities that ranged from negative 32 percent to 94 percent. Quarter-over-quarter benefits reveal similar variances. A comparison of third-quarter 2018 to third-quarter 2019 EIM benefits shows that EIM benefits decreased 73 percent, 46 percent, 47 percent, 2 percent, and 33 percent for CAISO, PAC, NV Energy, APS, and PSE, respectively, and increased less than 1 percent for PGE. While Idaho Power and PowerEx were not included in Staff's analysis because they did not have two full years of participation in the EIM, the same quarter-over-quarter comparison reveals reductions in EIM benefits of 42 percent and 61 percent, respectively.[8] The Company has attached a summary of quarterly EIM benefits achieved by each participant, as Exhibit 204, which illustrates the volatility of EIM benefits.

As a final example, updating Staff's growth factor methodology with CAISO's Fourth Quarter 2019 Western EIM Benefits Report, would reduce Staff's proposed growth factor of 22 percent to 8 percent. Simply replacing one quarter of EIM benefits in Staff's proposed methodology produces a growth factor that is nearly one-third of the original proposal. Due to this volatility it is inappropriate to use historical EIM benefits as a basis for a forecast adjustment by utilizing a simple averaging method.

[8] The Q3 2018 benefit for Idaho Power is based on the Company's estimate. In Q4 2018 an issue was discovered with CAISO's benefit methodology, as more fully described on page 12. Although CAISO did not republish the results for Q3 2018 or prior quarters, it did provide Idaho Power with one month of corrected results for Q3 2018 and Q2 2018, which Idaho Power extrapolated to estimate benefits for both quarters.

Q. What is the Company's second concern with Staff's proposed growth factor methodology?

A. The historical EIM benefits used in Staff's proposed growth factor methodology are likely flawed. In January 2019, upon receiving CAISO's Fourth Quarter 2018 Western EIM Benefits Report, the Company evaluated the CAISO benefit calculation and determined that the CF methodology was excluding some dispatchable lower-priced resources. The reason for this was that CAISO was using the transfer price[9] as a floor. Only resources with dispatchable capacity at bids equal to or higher than the transfer price were included in the CF calculation. Any resources with dispatchable capacity at bids lower than the transfer price were excluded from the CF calculation. In other words, in the Company's view, the CF was not using the least-cost available resources and therefore was overstating CF cost savings and ultimately the EIM benefits.

CAISO agreed to correct this modeling assumption for all EIM entities for the fourth quarter of 2018 and going forward. Additionally, CAISO re-ran the fourth quarter 2018 benefits calculation for all entities using the corrected modeling methodology. However, due to the administrative work required, CAISO chose not to re-run or re-publish prior quarters' Western EIM Benefits Reports for the EIM entities utilizing the corrected modeling methodology. Consequently, all CAISO EIM benefits prior to the fourth quarter of 2018 may be inaccurate and thus inappropriate to use as a basis for an adjustment to Idaho Power's EIM benefits forecast.

Q. What is the Company's third concern with Staff's proposed growth factor methodology?

A. Staff's growth factor methodology does not incorporate any data specific to Idaho Power and relies solely on historical benefits achieved by other EIM participants. Each

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[9] The transfer price is the average price of transfers between the Company and adjacent EIM Balancing Authority Areas.

entity contributes to the EIM differently through unique resource portfolios, transmission capacity, system operations, etc. Idaho Power itself is unique in that it is a predominately hydro-based utility, unlike most of the other EIM participants. Staff's methodology is unduly broad in that it assumes that benefits achieved by other participants will be similarly achieved by Idaho Power. It is unreasonable to adjust the Company's forecast of EIM benefits when the basis of the adjustment has limited relation to Idaho Power.

Q. Is application of a growth factor necessary?

A. No. To the extent that actual EIM benefits achieved are greater than forecast, these benefits will be realized through lower actual NPSE and will be captured through the Power Cost Adjustment Mechanism ("PCAM"), which tracks and trues-up deviations in forecast NPSE included in the APCU and actual NPSE, similar to the other NPSE components.

<u>Forecast OHAG Expense at Valmy</u>

Q. Please explain Staff's issue regarding OHAG expense at Valmy.

A. Staff has concerns with the methodology for calculating OHAG expense as it pertains to Valmy due to Idaho Power's cessation of participation in Valmy Unit 1 as of December 31, 2019. The North Valmy Project Framework Agreement between NV Energy and Idaho Power ("Framework Agreement"), approved by the Commission in Order No. 19-341 on October 15, 2019, established the agreement to allow Idaho Power to cease participation in Valmy Unit 1 while NV Energy continues to operate the unit. Staff believes there may be sufficient reason to alter the forecast of OHAG expense for Valmy given the terms of the Framework Agreement.

Q. Does Staff propose an adjustment to the forecast of OHAG expense based on the Framework Agreement?

A. While Staff offers a general concept for how the adjustment would be calculated, Staff notes that it continues to work through the Framework Agreement to determine the exact manner in which Idaho Power will share in OHAG expenses with NV Energy. Staff also explains that it endeavors to ascertain the percentage of OHAG costs Idaho Power will now pay compared to the amount it previously paid due to the new agreement.[10]

Q. Is an adjustment to the forecast of OHAG expenses needed based on the Framework Agreement?

A. No. Idaho Power appreciates Staff's recognition of the cessation of participation in Valmy Unit 1 and the potential need to adjust the OHAG methodology, as well as a proposal for how the adjustment might be determined. However, based on the terms of the Framework Agreement, Idaho Power must continue to pay its fixed proportional share, 50 percent, of OHAG expenses at Valmy, regardless of its exit from Unit 1.

Q. Has Idaho Power provided the Framework Agreement to support this conclusion?

A. Yes. Idaho Power has provided the Framework Agreement as Confidential Exhibit 205. As noted within the Fee Schedule of the Framework Agreement, Idaho Power must continue to pay 50 percent of the actual costs of Common Facility Fixed Operation and Fixed Maintenance costs, Fuel Handling Fixed Operations and Maintenance Expenses, and Administrative and General Costs.[11] OHAG expenses fall within these categories of costs that Idaho Power is required to continue paying.

Q. It is appropriate to adjust the forecast of OHAG expense given that Valmy Unit 1 will likely run less and therefore costs will be lower in the future?

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[10] Staff/300, Gibbens/8-9.

[11] See page 5 of Exhibit A, Fee Schedule, to the North Valmy Project Framework Agreement Between NV Energy and Idaho Power, Confidential Exhibit 205.

A. No. As Staff correctly described in Opening Testimony, OHAG expenses include: (1) the cost of diesel burned at the plant for startup and flame stabilization, (2) labor, equipment, materials, supplies, and related overhead loading on these costs to move coal from the train trestle to the coal silos, and (3) labor associated with coal fuel procurement and routine fuel analysis. Because the vast majority of these expenses are more fixed in nature and do not vary with output of the plant, it is expected that these expenses will continue to be incurred by Idaho Power until Valmy is retired. It is therefore appropriate to continue using the existing methodology, which relies on historical OHAG expense data and trends. Idaho Power does note that the per-unit cost modeled within AURORA, which reflects the variable portion of these expenses, has been adjusted to reflect expected costs and generation at Valmy due to Idaho Power's exit from Unit 1.

2020 Operations at Boardman

Q. Please provide background for this issue.

A. Boardman is required to cease coal-fired operation by the end of December 2020. Due to the high costs associated with coal removal, Idaho Power and PGE are strategically planning coal purchases in order to deplete the coal inventory before the plant shuts down, with a target depletion date of no later than October 31, 2020. Therefore, the Company modeled October 2020 as the last month of planned operations in AURORA, which aligns with the approach agreed upon for PGE in its 2020 Annual Power Cost Update Tariff, Docket No. UE 359, approved in Order No. 19-329.

Q. Please describe Staff's concern regarding the planned operations at Boardman in 2020.

A. Staff correctly observes that it is feasible that Boardman will be dispatched in November and December of 2020 if there is coal remaining and it is economic to run the plant. As explained by the Company's response to Staff's Data Request No. 49,[12] if this does occur, both the costs and benefits of dispatching the plant will be captured through the PCAM. Staff believes this is insufficient and that any benefits associated with the economic dispatch of Boardman in November and December should be returned to customers.[13]

Q. How does Staff propose to pass these benefits to customers?

A. Staff proposes that Idaho Power track any benefits as the difference between the settled Mid-Columbia market electricity price and the Boardman dispatch cost, with any realized value being included as an offset to NPSE in the 2022 APCU.[14] Essentially, the benefits would be tracked separately from other NPSE and would be excluded from the PCAM and its deadbands.

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

A. Idaho Power does not agree with Staff's proposal to separately track any realized benefits and include them as offset to NPSE in a future APCU proceeding. Determining NPSE components to be included or excluded from the PCAM and its deadbands in a piecemeal fashion is not appropriate, nor is it within the scope of this docket.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

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[12] Staff Exhibit/202, Soldavini/3.

[13] Staff/200, Soldavini/12, lines 15-21.

[14] Soldavini/13.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Reply Testimony of Nicole A. Blackwell

Idaho Power's Supplemental Response to
Staff's Data Request No. 24

March 3, 2020

UE 366 – 2020 APCU – Supplemental Response to Staff's DR 24

TOPIC OR KEYWORD: PURPA or QFs

STAFF'S DATA REQUEST NO. 24:

Please provide the following information in Excel format:

a. **Projected QF supplied power for each QF, as reflected in rates for each test year from 2015 through 2020. Please include MWh, MW and the projected purchased power cost in dollars.**
b. **Actual QF supplied power for each QF, for each test year from 2015 through 2019. Please include MWh, MW and the actual purchased power cost in dollars.**
c. **The ratio of actual to projected QF purchased power costs for each test year from 2015 through 2019.**

IDAHO POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S DATA REQUEST NO. 24:

Idaho Power provides the following supplemental response to Staff's Data Request No. 24.

Please see the attached confidential Excel file which includes projected QF purchased power costs and actual QF purchased power costs for the 2015, 2016, 2017, and 2018 APCU test years. Please note that both the projected and actual QF purchased power costs included in the confidential Excel file have been re-priced to reflect a non-levelized payment stream. Per Commission Order No. 85-010, the Company is required to reflect a non-levelized payment stream in rates for QF power purchases despite many of the QF contracts having payment provisions that require the Company to provide levelized payments over the length of the contract.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Reply Testimony of Nicole A. Blackwell

CONFIDENTIAL Attachment
Idaho Power's Supplemental Response to
Staff's Data Request No. 24

2016-2018 APCU October Update PURPA Forecast
Versus Actual PURPA Expense and Generation for April 2016 – March 2019

March 3, 2020

EXHIBIT 202 IS CONFIDENTIAL PER PROTECTIVE ORDER NO. 19-379 AND WILL BE PROVIDED SEPARATELY

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Reply Testimony of Nicole A. Blackwell

Idaho Power's Response to Staff's Data Request No. 52

March 3, 2020

UE 366 – 2020 APCU - Responses to Staff's Data Request Nos. 50-54

TOPIC OR KEYWORD: PURPA

STAFF'S DATA REQUEST NO. 52:

Describe the steps taken by Idaho Power to ensure the accuracy of its forecast, A) Solar and B) Solar.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 52:

Idaho Power's cogeneration and small power production ("CSPP") forecast included in the APCU is based on the average monthly output of historical actual generation, up to five years, from PURPA qualifying facilities ("QF") under contract with Idaho Power, and contract rates that are approved by the Commission. Where historical generation is not available from a QF that is under contract, but not online, Idaho Power relies on estimates of generation provided by the QF in accordance with the QF's contract. Idaho Power reviews the estimates provided by the QFs to ensure they are reasonable and consistent with other projects of the same resource type, facility characteristics, size, and location of the QF. In summary, the development of Idaho Power's CSPP forecast is a prescriptive process that relies on contract rates approved by the Commission and actual historical generation, when available, or generation estimates provided by the QF.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Reply Testimony of Nicole A. Blackwell

CAISO Western EIM Quarterly Benefits

March 3, 2020

CAISO Western EIM Quarterly Benefits [1]

(millions $)

EIM Entity	Q4-2017	Q1-2018	Q2-2018	Q3-2018	Q4-2018	2018 Total	Q1-2019	Q2-2019	Q3-2019	Q4-2019	2019 Total	% Change Q1-2019 vs. Q1-2018	% Change Q2-2019 vs. Q2-2018	% Change Q3-2019 vs. Q3-2018	% Change Q4-2019 vs. Q4-2018	% Change YE Q3-2019 vs. YE Q3-2018	% Change YE 2019 vs. YE 2018
California ISO (Entered 11/2014)	$ 4.52	$ 14.85	$ 27.93	$ 21.02	$ 4.14	$ 67.94	$ 13.08	$ 23.53	$ 5.77	$ 2.36	$ 44.74	-11.9%	-15.8%	-72.5%	-43.0%	-31.9%	-34.1%
PacifiCorp (Entered 11/2014)	$ 6.83	$ 10.51	$ 11.67	$ 17.82	$ 21.68	$ 61.68	$ 23.76	$ 15.15	$ 9.54	$ 11.32	$ 59.77	126.1%	29.8%	-46.5%	-47.8%	49.8%	-3.1%
NV Energy (Entered 12/2015)	$ 6.45	$ 4.17	$ 5.34	$ 11.09	$ 4.95	$ 25.55	$ 5.71	$ 4.62	$ 5.92	$ 6.62	$ 22.87	36.9%	-13.5%	-46.6%	33.7%	-21.6%	-10.5%
Arizona Public Service Company (Entered 10/2016)	$ 10.00	$ 5.90	$ 8.59	$ 20.78	$ 10.03	$ 45.30	$ 8.20	$ 8.55	$ 20.36	$ 17.37	$ 54.48	39.0%	-0.5%	-2.0%	73.2%	4.1%	20.3%
Puget Sound Energy (Entered 10/2016)	$ 2.83	$ 3.01	$ 2.32	$ 4.44	$ 3.91	$ 13.68	$ 7.21	$ 3.06	$ 2.97	$ 2.91	$ 16.15	139.5%	31.9%	-33.1%	-25.6%	36.1%	18.1%
Portland General Electric (Entered 10/2017)	$ 2.83	$ 3.64	$ 5.34	$ 9.47	$ 9.12	$ 27.57	$ 11.74	$ 10.89	$ 9.48	$ 10.76	$ 42.87	222.5%	103.9%	0.1%	18.0%	93.8%	55.5%
Idaho Power Company [2] (Entered 04/2018)			$ 5.58	$ 9.29	$ 5.82	$ 20.69	$ 8.45	$ 8.33	$ 5.36	$ 6.09	$ 28.23		49.3%	-42.3%	4.6%		
PowerEx (Entered 04/2018)			$ 2.27	$ 2.65	$ 2.92	$ 7.84	$ 7.23	$ 3.06	$ 1.04	$ 0.61	$ 11.94		34.8%	-60.8%	-79.1%		
BANC (Entered 04/2019)								$ 8.81	$ 4.37	$ 2.68	$ 15.86						
Total/Average	$ 33.46	$ 42.08	$ 69.04	$ 96.56	$ 62.57	$ 270.25	$ 85.38	$ 86.00	$ 64.81	$ 60.72	$ 296.91	92.0%	27.5%	-38.0%	-8.2%	21.7%	7.7%

[1] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

[2] The Q2 and Q3 2018 benefits for Idaho Power are based on the Company's estimate, not CAISO's published benefits. In Q4 2018 an issue was discovered with CAISO's benefit methodology. Although CAISO did not re-publish prior quarter results, it did provide Idaho Power with one month of corrected results for Q2 and Q3 2018, which the Company extrapolated to estimate benefits for both quarters.

Idaho Power/205
Witness: Nicole A. Blackwell

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Reply Testimony of Nicole A. Blackwell

North Valmy Project Framework Agreement
Between
Sierra Pacific Power Company d/b/a NV Energy and Idaho Power Company

March 3, 2020

EXHIBIT 205 IS CONFIDENTIAL PER PROTECTIVE ORDER NO. 19-379 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 366 on the date indicated below by U.S. mail addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: March 3, 2020

Alisha Till

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