ORDER NO. 20-164

ENTERED May 21 2020

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 366

In the Matter of IDAHO POWER COMPANY, 2020 Annual Power Cost Update.	ORDER

DISPOSITION: STIPULATION ADOPTED; ANNUAL POWER COST UPDATE APPROVED

We adopt the parties' stipulation and approve Idaho Power Company's Annual Power Cost Update (APCU). The APCU updates the company's net power supply expenses and results in new rates to go into effect June 1, 2020.

I. INTRODUCTION

In Order No. 08-238, we approved an automatic adjustment clause for Idaho Power that allows the company to annually update its net power supply expense (NPSE) included in rates. The APCU is comprised of two components: an October Update and a March Forecast. The October Update contains the company's forecasted net power supply expense reflected on a normalized and unit basis for an April through March test period. The March Forecast contains the company's net power supply expenses based on updated actual forecast conditions. The APCU mechanism allows for the rates from the October Update and March Forecast to become effective on June 1 of each year.

II. PROCEDURAL HISTORY

On October 31, 2019, Idaho Power filed testimony and exhibits for its 2020 APCU. The October Update estimated normalized power supply expenses for the 12-month test year, April 2020 through March 2021.[1] Staff filed opening testimony on February 4, 2020. Idaho Power filed rebuttal and cross-answering testimony on March 3, 2020. The company subsequently filed testimony and exhibits for the March Forecast on March 24, 2020. The procedural schedule was suspended on April 6, 2020, to facilitate settlement discussion among the parties.

[1] Idaho Power/100 Blackwell/21 (Oct 31, 2019).

On April 15, 2020, the company, CUB, and Staff of the Oregon Public Utility Commission filed a stipulation and exhibits, attached as Appendix A, settling all of the outstanding issues between the parties. The stipulation was accompanied by joint testimony from the parties in support of their stipulation. Idaho Power moved to admit the stipulation, and filed a second motion on April 16, 2020, to admit the three rounds of testimony from company witness Nicole A. Blackwell and the joint testimony.

III. DISCUSSION

A. The October Update

Idaho Power's 2020 October Update discussed utilization of the AURORA model, which simulates the economic dispatch of the company's resources to determine the NPSE for the APCU.[2] The model employs the following variables updated on an annual basis: (1) fuel prices and transportation costs, (2) wheeling expenses, (3) planned outages and forced outage rates, (4) heat rates, (5) forecast of normalized load and normalized sales, (6) contracts for wholesale power and power purchases and sales, (7) forward price curve, (8) Public Utility Regulatory Policies Act of 1978 (PURPA) expenses, and (9) the Oregon state allocation factor.[3] Each variable input was discussed individually in Idaho Power's opening testimony.[4]

The October Update presented Idaho Power's estimate of incremental costs and benefits associated with participating in the Western Energy Imbalance Market (EIM) to be included in the 2020 APCU. The company proposed to set estimated EIM benefits at $724,599 on an Oregon allocation basis, with costs reflected as $145,743.[5] Idaho Power also described the methodology for quantifying EIM benefits, and explained that CAISO's methodology for the calculation of EIM benefits uses assumptions problematic for hydro-generating utilities like Idaho Power. The company noted that a factor in the CAISO methodology assumed that bids submitted for each participating resource reflect the true dispatch costs, or economic value, of those resources. Idaho Power stated that it bids hydro resources on operational need rather than dispatch costs:

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[2] Idaho Power/100, Blackwell/4. Witness Nicole A. Blackwell defines the AURORA model as follows: "The AURORA model is a comprehensive electric resource dispatch model that simulates the economic dispatch of the Company's resources to determine NPSE for the APCU. The Commission has also accepted the use of AURORA to determine NPSE for general rate cases, marginal cost analyses, and resource modeling for the Company's Integrated Resource Plan."
[3] Idaho Power/100, Blackwell/4-5.
[4] Idaho Power/100, Blackwell/5-11.
[5] Idaho Power/100, Blackwell/14 and 20.

> Idaho Power utilizes various pricing tiers for its hydro resources to protect the water from overuse in the market and to adhere to regulated water management policies. The pricing tiers that Idaho Power uses are based upon certain operational parameters and can result in high bid prices when it is necessary to cease or limit water flows for a particular hydro resource's market participation. When Idaho Power operators move water into the higher tiers, which have a higher bid price, it is a response to operational needs and does not reflect market benefits.[6]

Idaho Power's exhibits calculate a total system NPSE of $376.8 million based on normalized customer-level annual sales of 15,012,868 megawatt-hour (MWh) for test year April 2020 through March 2021.[7] Based on this NPSE and customer usage, the calculations resulted in a cost per unit of $25.10 per MWh, a decrease from last year's October Update price of $25.40 per MWh.[8] The decrease is due to several factors, notably a decrease in coal and natural gas expenses (due to a decrease in generation provided by each resource), and decreases in PPA expenses. PURPA and market purchased power expenses both increased, while surplus sales revenue decreased.[9]

For the 2020 October Update, the company calculated the Oregon jurisdictional share of total NPSE by multiplying the cost per unit of $25.10 per MWh by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April through March test period, consistent with the methodology approved in the 2017 stipulation. Idaho Power then calculated the incremental Oregon jurisdictional NPSE by comparing the 2020 October Update Oregon jurisdictional share of total NPSE to the NPSE recovery under current approved rates from the 2019 APCU October Update, resulting in an incremental revenue requirement credit to Oregon customer rates of $0.2 million.[10] The company's revenue spread methodology for the 2020 October Update allocated the incremental revenue requirement to individual customer classes on the basis of the methodology agreed upon in the settlement stipulation approved by Order No. 18-170 in docket UE 333.[11]

On February 4, 2020, Commission Staff filed opening testimony and exhibits. Staff's testimony raised concerns related to the following: the Company's estimated EIM benefits, Idaho Power's compliance with previous Commission orders regarding OHAG and rate spread, Staff's review of the load forecast, natural gas price forecast update, and

[6] Idaho Power/100, Blackwell/15-16.
[7] Idaho Power/100, Blackwell/21.
[8] *Id.*
[9] *Id.* at 21-22.
[10] Idaho Power/100, Blackwell/23-24.
[11] *Id*. at 24.

other general updates, the Company's forecasted PURPA expense, the AURORA model's forward market re-pricing, Boardman 2020 operations, and Bridger Coal Company depreciation expenses. No other party filed opening testimony. No party filed reply testimony.[12]

B. The 2020 March Forecast

On March 24, 2020, Idaho Power filed the 2020 March Forecast component of the APCU. The October Update proposed a revenue decrease of $0.2 million. The company stated that the 2020 composite APCU with both the October Update and March forecast components included would result in a revenue increase of $556,283 or a 1.01 percent increase, to become effective June 1, 2020.[13]

The company explained that the increase in NPSE for the 2020 March forecast as compared to the October 2020 forecast is largely attributable to lower expected hydro generation, increased market purchased power and natural gas generation, and a decrease in off-system sales due to the decrease in coal generation:

> The reduction in hydro generation is expected to be met with increased market purchased power and natural gas generation. Although market prices and natural gas prices have decreased as compared to last year, the increased reliance on these resources in lieu of hydro generation increases NPSE. In addition, lower market prices reduce the company's ability to make economic off-system sales, which also contributes to higher NPSE for the April 2020 – March 2021 test period. The reduced off-system sales are reflected in the 65 percent reduction in coal-fired generation. Compared to last year, coal-fired plants have become less economic to run for surplus sales and to serve load. The reduction in coal-fired generation is also due to the cessation of operations from one unit at the North Valmy plant in 2019 and the Boardman plant in 2020.[14]

Idaho Power noted that the update to the October Update revenue requirement is due to changes to the company's forecast of Energy Imbalance Market ("EIM") benefits for the April 2020 through March 2021 test period.

[12] Stipulation at paragraph 11 (Apr 15, 2020).
[13] Idaho Power/200, Blackwell/1 (Mar 24, 2020).
[14] Idaho Power/200, Blackwell/2.

C. The Stipulation

On April 15, 2020, the company, Staff and CUB filed a joint stipulation. The joint parties agree that the Commission should adopt the APCU for Idaho Power subject to certain changes outlined in the stipulation. The parties assert that the results are in conformance with the methodology set forth in Order No. 08-238 and Order No. 10-191, and that rates produced are fair, just, and reasonable. They ask that the terms of the stipulation be made effective on June 1, 2020, as permitted by the APCU mechanism, with a revenue requirement increase of $528,931 or 0.96 percent overall.

The key provisions of the stipulation are as follows:

1. EIM Benefits

The joint parties agreed to include $16.9 million in EIM benefits in the 2020 APCU, which is $0.4 million higher than the EIM benefits calculated by Idaho Power in the March Forecast. While the joint parties do not agree that the methodology used by Idaho Power to calculate the forecasted EIM benefits is reasonable nor that the methodology used to determine the agreed-upon increase is reasonable, the joint parties agree that the company's forecasted EIM costs for the 2020 APCU are reasonable, and therefore agree to the joint, stipulated position. The joint parties emphasize, "The agreement to include these costs is the result of a compromise of positions and should not be viewed as reflecting any party's agreement to this approach in other circumstances."[15]

2. Contract Delay Rate (CDR)

The joint parties agree that Idaho Power will modify the CDR adjustment to the PURPA forecast included in the March Forecast of the APCU with respect to the treatment of new projects from the prior APCU that failed to come online. Under the existing CDR methodology originally filed in this case, for any new PURPA project expected to come online during the APCU forecast test period, the commercial operation date (COD) is delayed by the average number of days of Idaho Power's previously new PURPRA projects (actual COD minus expected COD) over the last three years. In the stipulation, the joint parties now add a third step to the CDR adjustment process: "A project in this category will be treated as new in the current APCU and will be subject to the three-year

[15] Stipulation at 8-9 (Apr 15, 2020); Stipulating Parties/100 Enright, Blackwell, Gehrke /8-9 (April 15, 2020).

average CDR for the March Forecast, using the methodology provided in Exhibit 1 of the stipulation."[16]

3. EIM benefit and CDR Adjustments

Based on the agreed-upon EIM benefit and CDR adjustments, the joint parties agree to an Oregon-allocated revenue requirement increase of $528,931 or 0.96 percent overall.

IV. RESOLUTION

We will adopt a stipulation if it was supported by competent evidence in the record, appropriately resolves the issues in the case, and results in just and reasonable rates.

Both Staff and CUB conducted an investigation of the company's testimony and exhibits, served eleven rounds of data requests, and participated in settlement conferences. Staff also filed testimony in this docket. The issues raised by Staff and CUB were addressed at settlement meetings and workshops, as well as in the company's supplemental testimony. After negotiations, all parties reached agreement on all unresolved issues and have executed a stipulation. No person has filed an objection to the stipulation.

We have examined the stipulation, the stipulating parties' testimony, and the record. We find that the stipulation is supported by the record, which includes the company's testimony and exhibits describing the detailed calculations supporting both the 2020 October Update, the 2020 March Forecast, the joint parties' testimony, and the stipulated modifications to the March Forecast. We conclude that the resulting rates are just and reasonable, and adopt the stipulation in its entirety.

[16] *Id.* at 9.

V. ORDER

IT IS ORDERED that:

1. The stipulation between Idaho Power Company, Staff of the Public Utility Commission of Oregon, and the Oregon Citizens' Utility Board, attached as Appendix A, is adopted.

2. Idaho Power Company must file revised rate schedules consistent with this order to be effective no earlier than June 1, 2020.

Made, entered, and effective May 21 2020.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Mark R. Thompson
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
UE 366

In the Matter of IDAHO POWER COMPANY 2020 ANNUAL POWER COST UPDATE	**STIPULATION**

This Stipulation resolves all issues among the parties to Idaho Power Company's ("Idaho Power" or "Company") 2020 Annual Power Cost Update ("APCU") filed pursuant to Order No. 08-238.[1] The APCU updates the Company's net power supply expense ("NPSE") and results in new rates, which the mechanism permits to go into effect June 1, 2020.

PARTIES

1. The parties to this Stipulation are Staff of the Public Utility Commission of Oregon ("Staff"), the Oregon Citizens' Utility Board ("CUB"), and Idaho Power (together, the "Stipulating Parties").

BACKGROUND

2. Pursuant to Order No. 08-238, Idaho Power annually updates its NPSE included in rates through an automatic adjustment clause, the APCU. The APCU is comprised of two components—an "October Update" and a "March Forecast." The October Update establishes the prospective base or normalized level of NPSE for an April through March test period. The March Forecast contains the Company's forecast of expected NPSE over the same test period. Pursuant to Order No. 10-191 the Company adjusts base rates to reflect changes in revenue requirement related to the October Update, while the rates resulting from the March Forecast are listed on Schedule 55. The rates associated with the October Update

[1] *Re Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism*, Docket No. UE 195, Order No. 08-238 (Apr. 28, 2008).

and the March Forecast are intended, under the mechanisms, to become effective on June 1 of each year.

3. On October 31, 2019, Idaho Power filed testimony and exhibits for the 2020 October Update component of the APCU ("2020 October Update").[2] Pursuant to Order No. 08-238, Idaho Power reviewed all the inputs and provided changes in the 2020 October Update for the following variables: (1) fuel prices and transportation costs, (2) wheeling expenses, (3) planned outages and forced outage rates, (4) heat rates, (5) forecast of normalized load and normalized sales, (6) contracts for wholesale power and power purchases and sales, (7) forward price curve, (8) Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses, and (9) the Oregon state allocation factor.[3]

4. The test period for the 2020 October Update was April 2020 through March 2021 and included updates to the above-referenced variables for all Company-owned resources and updated sales and load forecasts.[4] The 2020 October Update specifically accounted for changes in coal and natural gas prices, generation and expenses related to contracts entered into pursuant to PURPA, and normalized system load.[5]

5. As part of the fuel expense update, the Company updated its forecast of Oil, Handling, and Administrative and General ("OHAG") expenses in accordance with the terms of the 2016 and 2017 APCU settlement stipulations.[6] Per the terms of the 2016 APCU settlement stipulation,[7] the per-unit OHAG expense included in the AURORA model was updated to reflect the amount of OHAG expense driven by Idaho Power's dispatch of each

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[2] *See* Idaho Power/100-109.

[3] Idaho Power/100, Blackwell/4-5.

[4] Idaho Power/100, Blackwell/2 and 5.

[5] Idaho Power/100, Blackwell/5-11.

[6] Idaho Power/100, Blackwell/7.

[7] *Re Idaho Power Company's 2016 Annual Power Cost Update*, Docket No. UE 301, Stipulation at 7 (May 11, 2016).

of its coal plants. The Company then separately accounted for its proportional share of the total OHAG expense incurred at each of its coal plants. Per the terms of the 2017 APCU settlement stipulation,[8] Idaho Power's proportional share of total OHAG expenses incurred at each of its coal plants was forecast using the three-year historical average of actual OHAG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate. Idaho Power also accounted for revenues received from or expenses paid to NV Energy (its ownership partner in the North Valmy Plant ("Valmy")) for use of the Company's unused capacity or the Company's use of NV Energy's unused capacity.

6. The 2020 October Update also included the Company's estimate of incremental costs and benefits associated with participation in the Western Energy Imbalance Market ("EIM").[9] Idaho Power proposed to include $15.6 million in system EIM benefits as an offset to NPSE in the 2020 October Update.[10] On an Oregon allocated basis, the EIM benefits to be included in the 2020 October Update total $724,599. Idaho Power determined that level of benefit by using the California Independent System Operator ("CAISO") report of EIM benefits, for October 2018 through September 2019, as a starting point, and then accounted for necessary adjustments to quantify ongoing cost-savings benefits specific to Idaho Power's participation in the EIM. The 2020 October Update also included Oregon-allocated EIM costs of $145,713.

7. The filed 2020 October Update resulted in a rate of $25.10 per megawatt-hour ("MWh"), representing a decrease of approximately 1.2 percent relative to last year's October Update rate of $25.40 per MWh.[11]

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[8] *Re Idaho Power Company's 2017 Annual Power Cost Update*, Docket No. UE 314, Stipulation at 7 (April 28, 2017).

[9] Idaho Power/100, Blackwell/13-19.

[10] Idaho Power/100, Blackwell/14.

[11] Idaho Power/100, Blackwell/21.

8. For the 2020 October Update, the Company calculated the Oregon jurisdictional share of total NPSE by multiplying the rate of $25.10 per MWh by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April through March test period.[12] Idaho Power then calculated the incremental Oregon jurisdictional NPSE by comparing the 2020 October Update Oregon jurisdictional share of total NPSE to the NPSE recovery under current approved rates from the 2019 APCU October Update, resulting in a revenue requirement decrease of approximately $0.2 million.[13]

9. The Company's revenue spread methodology for the 2020 October Update allocated the incremental revenue requirement to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the test period, consistent with the stipulation from the 2018 APCU.[14] In addition, consistent with the stipulation from the 2018 APCU, any rate increases resulting from application of this revenue spread methodology as applied to a customer class were capped at 3 percent above the overall average rate increase on a percentage of total revenue basis. In the 2020 October Update, the overall average rate change as a percentage of total revenue is a decrease of 0.32 percent; therefore, any rate increases applied to individual customer classes were capped at 2.68 percent. Application of the stipulated revenue spread methodology results in rate changes for all individual customer classes below the 2.68 percent cap. The highest rate change is 2.50 percent for Large Power Transmission Service customers (Tariff Schedule 19T).

10. On October 31, 2019, CUB filed its Notice of Intervention. On December 13, 2019, Administrative Law Judge ("ALJ") Christopher J. Allwein held a prehearing conference

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[12] Idaho Power/100, Blackwell/23.

[13] Idaho Power/100, Blackwell/24.

[14] Idaho Power/100, Blackwell/24; Idaho Power/108.

at which the parties agreed upon a procedural schedule that would allow the Public Utility Commission of Oregon ("Commission") to issue an order on Idaho Power's 2020 APCU prior to June 1, 2020.[15]

11. The Stipulating Parties held an initial workshop on January 15-16, 2020, to discuss the 2020 October Update filing. Staff and CUB served discovery on Idaho Power and conducted a thorough investigation of the 2020 October Update.

12. On February 4, 2020, Staff filed Opening Testimony. Staff's testimony addressed the Company's estimated EIM benefits; Idaho Power's compliance with previous Commission orders regarding OHAG and rate spread; Staff's review of the load forecast, natural gas price forecast update, and other general updates; the Company's forecasted PURPA expense; the AURORA model's forward market re-pricing; Boardman 2020 operations; and Bridger Coal Company ("BCC") depreciation expenses.

13. CUB did not file Opening Testimony.

14. Idaho Power filed Reply Testimony on March 3, 2020.

15. On March 24, 2020, Idaho Power filed the 2020 March Forecast component of the APCU ("2020 March Forecast"). The 2020 March Forecast consisted of direct testimony describing the Company's estimate of the expected NPSE for the upcoming water year—April 2020 through March 2021.[16] Order No. 08-238 calls for the March Forecast to update the following variables: fuel prices, transportation costs, wheeling expenses, planned and forced outages, heat rates, forecast of normalized sales and loads updated for significant changes since the October Update, forecast hydro generation, wholesale power purchase and sale contracts, forward price curve, PURPA expenses, and the Oregon state allocation factor.

[15] *Re Idaho Power Company's 2018 Annual Power Cost Update*, Docket No. UE 333, Prehearing Conference Memorandum at 1 (January 11, 2018).

[16] Idaho Power/200-208.

16. Idaho Power reviewed all the variables for the March Forecast and the following variables changed since the 2020 October Update: (1) fuel prices and transportation costs; (2) planned outages and forced outage rates; (3) heat rates; (4) forecast of hydro generation from stream flow conditions using the most recent water supply forecast from the Northwest River Forecast Center ("NWRFC") and current reservoir levels; (5) known power purchases and surplus sales made in compliance with the Company's Energy Risk Management Policy ("ERMP"); (6) forward price curve; and (7) PURPA contract expenses.[17]

17. The fuel prices were updated to reflect changes in forecast natural gas and coal costs.[18] At the plant level, the per-unit cost of production decreased at the Jim Bridger plant ("Bridger") from $39.34 per MWh to $37.67 per MWh, increased at the Boardman plant ("Boardman") from $26.98 per MWh to $32.48 per MWh.[19] Valmy was not economically dispatched by AURORA for the March Forecast, whereas the October Update included 0.21 million MWh.[20]

18. The updated natural gas price forecast reflected a decrease of $0.36 per MMBtu, relative to the 2020 October Update. The gas price forecast used for the October Update for Henry Hub was $2.71 per MMBtu, while the gas price forecast used for the March Forecast for Henry Hub was $2.35 per MMBtu.[21]

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[17] Idaho Power/200, Blackwell/5.

[18] Idaho Power/300, Blackwell/4-7.

[19] Idaho Power/300, Blackwell/6.

[20] *Id.*

[21] Idaho Power/300, Blackwell/8.

19. The Company also updated the hydro forecast.[22] The hydro generation forecasted for this year's March Forecast is 7.2 million MWh compared to 8.4 million MWh in last year's March Forecast, a 14 percent decrease.[23]

20. The March Forecast also included reduced PURPA generation relative to the October Update. The October Update included 345 average megawatts ("aMW") of available PURPA generation, whereas the PURPA generation included in the March Forecast was 339 aMW, a decrease of 6 aMW, or 1.7 percent, since the October Update.[24] Total PURPA expense included in the March Forecast is $218.2 million compared to $223.5 million included in the October Update, a decrease of $5.3 million, or 2.4 percent. PURPA expense included in the 2020 March Forecast is $2.2 million less than PURPA expense included in the 2019 March Forecast,[25] a decrease that is primarily due to the unexpected termination of a 4.5 MW biomass project. The March Forecast also included the Contract Delay Rate ("CDR") adjustment per the terms of the settlement in the 2018 APCU.[26]

21. The March Forecast also updated the Company's forecasted EIM benefits and costs. Idaho Power proposed to include $16.5 million in system EIM benefits as an offset to NPSE in the 2020 APCU. On an Oregon allocated basis, the EIM benefits to be included in the 2020 APCU total $749,691.[27] The updated forecast of EIM costs to be included in the 2020 APCU totals $150,390 on an Oregon allocated basis.[28]

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[22] Idaho Power/300, Blackwell/11-12.

[23] Idaho Power/300, Blackwell/12.

[24] Idaho Power/300, Blackwell/9-10.

[25] Idaho Power/300, Blackwell/14.

[26] Idaho Power/300, Blackwell/10.

[27] Idaho Power/300, Blackwell/17.

[28] Idaho Power/300, Blackwell/19.

22. The 2020 March Forecast included forecast NPSE of $412.3 million, or $17.4 million more than the 2019 March Forecast of NPSE of $394.9 million.[29] The 2019 March Forecast unit cost per MWh was $26.62 per MWh, compared to this year's March Forecast unit cost of $27.47 per MWh.[30] The overall revenue impact of the combined 2020 October Update and March Forecast is an increase of $0.56 million or 1.01 percent. The $0.56 million increase reflects a decrease of $0.22 million in base rate revenues associated with the October Update and a $0.78 million increase in Schedule 55 revenues associated with the March Forecast, as compared to what is currently included in Oregon customers' rates related to the 2019 APCU.[31]

23. Staff and CUB conducted a thorough investigation of the March Forecast.

24. Settlement conferences were held on February 10, 2020, and March 26, 2020. Ultimately the Stipulating Parties resolved all the issues in this case through these discussions, resulting in the settlement stipulation as described in this Agreement.

AGREEMENT

25. EIM Benefits: The Stipulating Parties agree to include $16.9 million in EIM benefits in the 2020 APCU, which is $0.4 million higher than the EIM benefits calculated by Idaho Power in the March Forecast. The Stipulating Parties do not agree that the methodology used by Idaho Power to calculate the forecasted EIM benefits is reasonable nor that the methodology used to determine the agreed-upon increase is reasonable. Every party reserves its rights to dispute the methodology used in this case in future proceedings. The Stipulating Parties agree that the Company's forecasted EIM costs for the 2020 APCU are reasonable. The parties emphasize that the agreement to include these costs and

[29] Idaho Power/300, Blackwell/14.

[30] Idaho Power/300, Blackwell/19-20.

[31] Idaho Power/300, Blackwell/22.

benefits in the APCU is the result of a compromise of positions and should not be viewed as reflecting any party's agreement to this approach in other circumstances.

26. Contract Delay Rate: The Stipulating Parties agree that Idaho Power will modify the CDR adjustment to the PURPA forecast included in the March Forecast of the APCU with respect to the treatment of new projects from the prior APCU that failed to come online. Under the existing CDR methodology originally filed in this case, for any new PURPA project expected to come online during the APCU forecast test period, the forecast generation and expense is included in the forecast beginning in the month in which the project is expected to come online. For example, if a new PURPA project is expected to come online in December of the APCU forecast test period, the forecast generation and expense for the project is included in the PURPA forecast beginning in December. The expected online date is then adjusted using the three-year average CDR of historical PURPA projects. The CDR is based on the average of differences in scheduled operation date and actual operation date for historical PURPA projects. The three-year historical average CDR is applied to any new PURPA project expected to come online during the forecast test period for the March Forecast of the APCU. In this settlement agreement, the Stipulating Parties agree to add a third step to the CDR adjustment process for any new PURPA project expected to come online during the prior APCU test year that failed to do so. A project under this category will be treated as new in the current APCU and will be subject to the three-year average CDR for the March Forecast. The methodology used to calculate the CDR for the 2020 APCU is provided as Exhibit 1 to this stipulation.

27. Based on the agreed-upon EIM benefit and CDR adjustment, the Stipulating Parties agree to a revenue requirement increase of $528,931 or 0.96 percent overall. This revenue requirement is supported by the following exhibits to this stipulation: Exhibit 2 shows the October Update NPSE based on the settlement terms, Exhibit 3 shows the March

Forecast NPSE based on the settlement terms, Exhibit 4 shows the Combined Rate based on the settlement terms, and Exhibit 5 shows the rate spread based on the settlement terms.

28. The Stipulating Parties agree that the Company's allocation methodology conforms to Commission precedent, as reflected in previous APCU stipulations, and should be approved.

29. The Stipulating Parties agree that the rate change resulting from the Stipulation results in rates that are fair, just, and reasonable, as required by ORS 756.040

30. The Stipulating Parties agree that rates agreed to by the terms of this Stipulation should be made effective on June 1, 2020, as permitted by the APCU mechanism.

31. The Stipulating Parties agree the result of this Stipulation is in conformance with the methodology adopted by the Commission in Order No. 08-238, as modified in subsequent APCU orders.

32. The Stipulating Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented.

33. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and any appeal, (if necessary) provide witnesses to sponsor this Stipulation at the hearing and recommend that the Commission issue an order adopting the settlements contained herein.

34. If this Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Stipulating Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

35. The Stipulating Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation, or adds any

material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

36. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

37. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

38. This Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: ______________________ on behalf of Stephanie Andrus

Date: April 15, 2020

IDAHO POWER

By: ______________________

Date: ______________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

36. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

37. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

38. This Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: ______________________________

Date: ______________________________

IDAHO POWER

By: Adam Lowney

Date: April 15, 2020

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

36. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

37. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

38. This Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: ______________________________

Date: ______________________________

IDAHO POWER

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: Michael P. Goetz

Date: April 14, 2020

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366

STIPULATION

Exhibit 1

QF Contract Delay Rate

April 15, 2020

3-Year Average Contract Delay Rate

New PURPA Projects by APCU Docket No.	Facility Type	Scheduled Operation Date	Actual Operation Date	Test Year		Operation Date Delay
UE 314: 2017 APCU				**4/1/2017**	**3/31/2018**	
Clark Canyon Hydro[1]	Hydro	6/1/2017	10/13/2017			134
North Gooding Main Hydro	Hydro	4/1/2017	10/8/2016			0
UE 333: 2018 APCU				**4/1/2018**	**3/31/2019**	
SISW LFGE	Biomass	10/1/2018	9/1/2018			-30
UE 350: 2019 APCU				**4/1/2019**	**3/31/2020**	
Baker Solar Center	Solar	12/31/2019	2/18/2020			49
Brush Solar	Solar	10/1/2019	12/26/2019			86
MC6 Hydro	Hydro	7/30/2019	NA			
Morgan Solar	Solar	10/1/2019	NA			
Ontartio Solar Center	Solar	12/31/2019	NA			
Vale 1 Solar	Solar	10/1/2019	NA			

3-Year Average Contract Delay Rate (CDR)	**60**

UE 366: 2020 APCU New PURPA Projects Subject to CDR	**Facility Type**	**Scheduled Operation Date**	**4/1/2020**	**3/31/2021**	**CDR Adjusted Operation Date**
MC6 Hydro [2]	Hydro	8/31/2020			10/29/2020
Morgan Solar [3]	Solar	4/15/2020			6/13/2020
Ontario Solar Center [4]	Solar	4/1/2020			5/30/2020
Vale 1 Solar [5]	Solar	5/1/2020			6/29/2020

[1] Clark Canyon Hydro terminated its PURPA contract on 10/31/2017.

[2] MC6 Hydro's original Scheduled Operation Date was 7/30/2019. The project now estimates an operation date of 8/31/2020.

[3] Morgan Solar's original Scheduled Operation Date was 10/1/2019. The project now estimates an operation date of 4/15/2020.

[4] Ontario Solar Center's original Scheduled Operation Date was 12/31/2019. The project now estimates an operation date of 4/1/2020.

[5] Vale 1 Solar's original Scheduled Operation Date was 10/1/2019. The project now estimates an operation date of 5/1/2020.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366

STIPULATION

Exhibit 2

October Update NPSE

April 15, 2020

ORDER NO: 20-164

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR APRIL 1, 2020 -- MARCH 31, 2021 (Multiple Gas Prices/91 Hydro Year Conditions)
Repriced Using UE 195 Settlement Methodology - 2020 October Update
AVERAGE

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	884,062.2	979,144.2	962,295.5	712,587.6	604,327.1	541,752.0	525,094.3	455,116.8	674,522.3	826,467.3	795,636.9	843,400.6	8,804,407.0
	Bridger													
2	Energy (MWh)	254.3	-	7,165.3	127,648.4	138,388.2	45,743.0	14,715.1	106,370.6	161,793.8	72,848.4	31,317.5	6,636.5	712,881.1
3	Expense ($ x 1000)	$ 270.2	$ 261.0	$ 513.0	$ 4,669.8	$ 5,074.5	$ 1,864.2	$ 784.7	$ 3,987.8	$ 5,838.0	$ 2,869.6	$ 1,407.1	$ 504.6	$ 28,044.7
	Boardman													
4	Energy (MWh)	4,384.8	2,435.0	6,576.9	31,264.3	32,452.7	25,598.5	18,630.4	-	-	-	-	-	121,342.7
5	Expense ($ x 1000)	$ 136.1	$ 86.6	$ 194.9	$ 823.5	$ 853.1	$ 675.8	$ 503.5	$ -	$ -	$ -	$ -	$ -	$ 3,273.5
	Valmy													
6	Energy (MWh)	440.6	-	2,722.4	23,385.2	20,964.4	10,090.6	6,184.3	18,897.0	29,660.6	49,579.6	31,590.2	20,650.1	214,165.1
7	Expense ($ x 1000)	$ 319.9	$ 304.5	$ 395.3	$ 1,060.5	$ 986.8	$ 639.2	$ 514.9	$ 917.8	$ 1,243.2	$ 1,348.9	$ 979.4	$ 753.2	$ 9,463.6
	Langley Gulch													
8	Energy (MWh)	168,394.1	201,775.7	193,108.7	198,950.8	199,048.7	194,019.1	199,317.7	191,213.0	190,172.7	170,123.7	143,009.8	155,777.5	2,204,911.3
9	Expense ($ x 1000)	$ 2,246.1	$ 2,286.5	$ 2,220.7	$ 3,095.6	$ 3,202.8	$ 3,031.6	$ 2,970.7	$ 3,852.6	$ 4,751.3	$ 4,064.3	$ 3,093.0	$ 2,856.8	$ 37,671.9
	Danskin													
10	Energy (MWh)	29,201.8	63,773.4	81,510.0	105,061.3	98,862.6	83,832.3	65,865.8	18,112.3	5,574.5	3,385.9	4,111.3	9,790.2	569,081.3
11	Expense ($ x 1000)	$ 677.4	$ 1,275.7	$ 1,681.2	$ 2,822.5	$ 2,701.1	$ 2,244.2	$ 1,681.0	$ 577.2	$ 221.5	$ 131.0	$ 144.0	$ 298.4	$ 14,455.3
	Bennett Mountain													
12	Energy (MWh)	16,851.2	34,586.7	47,877.9	68,478.3	61,413.1	45,703.9	32,515.8	8,976.2	2,172.1	1,065.0	1,591.3	5,564.0	326,795.4
13	Expense ($ x 1000)	$ 389.8	$ 694.7	$ 979.6	$ 1,817.9	$ 1,662.0	$ 1,220.1	$ 823.8	$ 286.6	$ 86.0	$ 40.7	$ 56.1	$ 172.4	$ 8,229.8
14	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 690.0	$ 712.5	$ 690.0	$ 712.5	$ 712.5	$ 690.0	$ 712.5	$ 690.0	$ 712.5	$ 711.2	$ 643.4	$ 711.2	$ 8,388.4
	Purchased Power (Excluding CSPP)													
15	Market Energy (MWh)	8,625.2	6,344.9	67,195.2	211,395.3	231,581.3	95,535.0	57,489.5	155,349.4	102,547.2	109,959.1	43,426.8	31,816.8	1,121,265.7
16	Elkhorn Wind Energy (MWh)	26,404.6	26,527.2	25,227.4	25,865.4	22,886.0	21,015.4	23,409.4	30,182.4	27,577.6	24,216.8	24,659.9	24,425.1	302,396.9
17	Neal Hot Springs Energy (MWh)	15,249.6	11,952.5	11,189.5	9,323.4	9,575.2	12,688.0	16,619.5	18,383.0	19,941.4	18,374.9	17,111.0	17,550.7	177,958.7
18	Raft River Geothermal Energy (MWh)	4,270.5	3,263.6	3,612.4	3,828.7	3,550.0	3,797.6	3,774.9	4,094.8	4,523.1	4,600.4	4,043.7	4,344.8	47,704.4
19	Total Energy Excl. CSPP (MWh)	54,549.9	48,088.1	107,224.5	250,412.8	267,592.4	133,036.0	101,293.3	208,009.6	154,589.3	157,151.2	89,241.4	78,137.3	1,649,325.8
20	Market Expense ($ x 1000)	$ 193.4	$ 126.5	$ 1,322.4	$ 9,082.8	$ 11,276.8	$ 4,248.1	$ 1,779.8	$ 5,206.5	$ 4,130.8	$ 4,340.5	$ 1,479.5	$ 898.8	$ 44,085.9
21	Elkhorn Wind Expense ($ x 1000)	$ 1,285.4	$ 1,291.3	$ 1,670.8	$ 2,055.8	$ 1,819.0	$ 1,391.8	$ 1,550.4	$ 2,398.9	$ 2,191.9	$ 1,652.1	$ 1,682.3	$ 1,224.7	$ 20,214.3
22	Neal Hot Springs Expense ($ x 1000)	$ 1,324.1	$ 1,037.8	$ 1,325.5	$ 1,325.3	$ 1,361.1	$ 1,503.0	$ 1,968.7	$ 2,613.2	$ 2,834.7	$ 2,214.5	$ 2,062.2	$ 1,550.4	$ 21,120.7
23	Raft River Geothermal Expense ($ x 1000)	$ 215.9	$ 165.0	$ 248.5	$ 316.1	$ 293.0	$ 261.2	$ 259.7	$ 338.0	$ 373.4	$ 318.3	$ 279.8	$ 221.0	$ 3,290.0
24	Total Expense Excl. CSPP ($ x 1000)	$ 3,018.8	$ 2,620.7	$ 4,567.2	$ 12,779.9	$ 14,749.9	$ 7,404.2	$ 5,558.6	$ 10,556.6	$ 9,530.7	$ 8,525.5	$ 5,503.9	$ 3,894.9	$ 88,710.9
	Surplus Sales													
25	Energy (MWh)	336,578.4	331,143.5	159,646.4	14,767.5	3,177.3	26,890.0	64,360.5	13,348.7	20,424.3	52,206.8	105,204.7	199,036.2	1,326,784.3
26	Revenue Including Transmission Costs ($ x 1000)	$ 6,843.1	$ 5,987.0	$ 2,847.9	$ 575.2	$ 140.3	$ 1,084.1	$ 1,806.8	$ 405.7	$ 746.0	$ 1,868.7	$ 3,250.2	$ 5,098.8	$ 30,653.8
27	Transmission Costs ($ x 1000)	$ 336.6	$ 331.1	$ 159.6	$ 14.8	$ 3.2	$ 26.9	$ 64.4	$ 13.3	$ 20.4	$ 52.2	$ 105.2	$ 199.0	$ 1,326.8
28	Revenue Excluding Transmission Costs ($ x 1000)	$ 6,506.5	$ 5,655.8	$ 2,688.3	$ 560.4	$ 137.1	$ 1,057.2	$ 1,742.5	$ 392.3	$ 725.6	$ 1,816.5	$ 3,145.0	$ 4,899.8	$ 29,327.1
29	Net Power Supply Expenses ($ x 1000)	$ 1,241.9	$ 2,586.5	$ 8,553.5	$ 27,221.8	$ 29,805.8	$ 16,712.1	$ 11,807.3	$ 20,476.3	$ 21,657.6	$ 15,874.7	$ 8,681.8	$ 4,291.6	**$ 168,911.0**
30	PURPA ($ x 1000)	$ 25,591.5	$ 24,383.8	$ 18,383.1	$ 16,279.5	$ 17,799.4	$ 16,617.6	$ 14,198.7	$ 15,356.4	$ 14,025.7	$ 18,382.5	$ 19,106.4	$ 23,437.1	$ 223,561.9
31	EIM Benefits													$ 16,886.3
32	Total Net Power Supply Expenses ($ x 1000)	$ 26,833.4	$ 26,970.3	$ 26,936.7	$ 43,501.3	$ 47,605.2	$ 33,329.7	$ 26,006.0	$ 35,832.7	$ 35,683.4	$ 34,257.2	$ 27,788.2	$ 27,728.7	**$ 375,586.5**
33	Sales at Customer Level (In 000s MWH)	1,033.794	1,091.012	1,265.207	1,548.646	1,616.825	1,436.194	1,123.870	1,039.822	1,167.969	1,311.961	1,248.050	1,129.515	15,012.868
34	Hours in Month	720	744	720	744	744	720	744	721	744	744	672	743	8,760
35	Unit Cost / MWH (for PCAM)	$25.96	$24.72	$21.29	$28.09	$29.44	$23.21	$23.14	$34.46	$30.55	$26.11	$22.27	$24.55	**$25.02**
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
36	Portion of Purchased Power considered HL Purchases	**64.25%**	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	
37	Purchased Power HL Price	$24.97	$23.16	$23.51	$49.85	$55.90	$50.19	$33.15	$36.00	$43.57	$42.99	$36.75	$30.12	
38	Portion of Surplus Sales considered HL Surplus Sales	**62.70%**	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	
39	Surplus Sales HL Price	$23.17	$21.49	$21.81	$46.25	$51.86	$46.57	$30.76	$33.40	$40.43	$39.89	$34.10	$27.95	
	Light Load													
40	Portion of Purchased Power considered LL Purchases	**35.75%**	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	
41	Purchased Power LL Price	$17.85	$14.15	$12.80	$30.59	$35.75	$34.18	$27.02	$29.04	$34.36	$33.16	$29.25	$24.89	
42	Portion of Surplus Sales considered LL Surplus Sales	**37.30%**	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	
43	Surplus Sales LL Price	$15.56	$12.34	$11.16	$26.68	$31.18	$29.81	$23.56	$25.33	$29.97	$28.92	$25.51	$21.70	

APPENDIX A

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366

STIPULATION

Exhibit 3

March Forecast NPSE

April 15, 2020

ORDER NO: 20-164

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2020 -- MARCH 31, 2021 (One Hydro Condition)
Repriced Using UE 195 Settlement Methodology - 2020 March Forecast

Settlement Stipulation
Exhibit 3

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	1,016,249.5	898,120.9	789,244.5	595,550.9	477,684.6	454,354.2	449,755.8	381,688.0	437,427.6	466,072.8	479,971.3	718,709.8	7,164,829.9
	Bridger													
2	Energy (MWh)	-	-	-	172,323.5	188,223.6	22,041.5	3,061.1	86,123.2	217,239.4	108,464.9	19,917.7	-	817,394.8
3	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ -	$ 6,001.8	$ 6,558.2	$ 768.3	$ 110.2	$ 3,034.9	$ 7,523.3	$ 3,990.9	$ 736.0	$ -	$ 28,723.6
4	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ 180.9	$ 197.6	$ 23.1	$ 3.2	$ 90.4	$ 228.1	$ 113.9	$ 20.9	$ -	$ 858.3
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ 5,820.9	$ 6,360.5	$ 745.2	$ 107.0	$ 2,944.4	$ 7,295.2	$ 3,877.0	$ 715.1	$ -	$ 27,865.3
6	IPC Share of OHAG Expense ($ x 1000)	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 2,923.0
7	Total Expense ($ x 1000)	$ 243.6	$ 243.6	$ 243.6	$ 6,064.5	$ 6,604.1	$ 988.8	$ 350.6	$ 3,188.0	$ 7,538.8	$ 4,120.6	$ 958.7	$ 243.6	$ 30,788.4
	Boardman													
8	Energy (MWh)	-	-	2,213.9	17,210.0	20,755.9	11,991.9	9,655.7	-	-	-	-	-	61,827.3
9	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ 71.7	$ 534.0	$ 637.7	$ 377.4	$ 310.4	$ -	$ -	$ -	$ -	$ -	$ 1,931.2
10	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 1.4	$ 10.5	$ 12.7	$ 7.3	$ 5.9	$ -	$ -	$ -	$ -	$ -	$ 37.7
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 70.4	$ 523.5	$ 625.0	$ 370.0	$ 304.5	$ -	$ -	$ -	$ -	$ -	$ 1,893.5
12	IPC Share of OHAG Expense ($ x 1000)	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ -	$ -	$ -	$ -	$ -	$ 114.9
13	Total Expense ($ x 1000)	$ 16.4	$ 16.4	$ 86.8	$ 540.0	$ 641.5	$ 386.5	$ 320.9	$ -	$ -	$ -	$ -	$ -	$ 2,008.5
	Valmy													
14	Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
15	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	IPC Share of OHAG Expense ($ x 1000)	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 4,018.9
19	Usage Charges Paid to IPC ($ x 1000)	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 115.5
20	Total Expense ($ x 1000)	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 3,903.4
	Langley Gulch													
21	Energy (MWh)	138,456.6	202,471.5	194,723.1	199,049.8	199,049.8	194,745.6	199,479.0	193,242.9	200,988.2	211,641.6	180,891.3	160,894.0	2,275,633.3
22	Expense ($ x 1000)	$ 1,592.1	$ 2,070.6	$ 2,134.3	$ 2,532.0	$ 2,913.8	$ 2,636.3	$ 3,085.1	$ 4,150.6	$ 5,569.9	$ 5,197.2	$ 3,925.2	$ 2,870.0	$ 38,677.1
	Danskin													
23	Energy (MWh)	19,734.1	70,927.6	82,510.4	143,114.8	129,250.1	125,274.0	59,870.3	12,400.8	1,808.1	9,971.1	11,821.4	11,670.2	678,352.9
24	Expense ($ x 1000)	$ 390.5	$ 1,270.7	$ 1,595.8	$ 3,223.0	$ 3,315.8	$ 2,933.4	$ 1,579.1	$ 436.7	$ 81.0	$ 397.5	$ 421.9	$ 343.1	$ 15,988.4
	Bennett Mountain													
25	Energy (MWh)	9,565.1	40,873.8	54,834.7	88,389.0	79,713.8	78,874.3	31,372.6	6,933.2	352.1	4,410.1	6,164.8	6,087.4	407,570.9
26	Expense ($ x 1000)	$ 190.3	$ 733.5	$ 1,050.6	$ 1,943.6	$ 1,994.6	$ 1,830.7	$ 822.9	$ 246.9	$ 16.0	$ 178.4	$ 221.9	$ 182.0	$ 9,411.4
27	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 688.6	$ 711.2	$ 778.6	$ 804.2	$ 804.2	$ 778.6	$ 711.2	$ 688.6	$ 711.2	$ 711.2	$ 643.4	$ 711.2	$ 8,742.6
	Purchased Power (Excluding PURPA)													
28	Market Energy (MWh)	1,338.7	661.2	86,033.9	201,858.6	300,987.1	136,678.5	145,765.2	243,803.9	309,563.0	372,772.1	239,537.9	53,447.3	2,092,447.4
29	Elkhorn Wind Energy (MWh)	26,836.0	26,268.6	24,879.8	26,854.8	23,393.8	21,207.8	22,955.8	28,626.4	28,597.0	28,064.8	26,555.2	25,454.9	309,694.6
30	Neal Hot Springs Energy (MWh)	15,249.6	11,952.5	11,189.5	9,323.4	9,575.2	12,688.0	16,619.5	18,383.0	19,941.4	18,374.9	17,111.0	17,550.7	177,958.7
31	Raft River Geothermal Energy (MWh)	7,226.9	5,523.0	6,113.3	6,479.3	6,007.6	6,426.7	6,388.3	6,929.7	7,654.5	7,785.3	6,843.1	7,352.7	80,730.6
32	Total Energy Excl. PURPA (MWh)	50,651.2	44,405.3	128,216.4	244,516.0	339,963.7	177,001.0	191,728.8	297,743.0	365,755.9	426,997.1	290,047.2	103,805.7	2,660,831.3
33	Market Expense ($ x 1000)	$ -	$ -	$ 1,014.4	$ 5,218.6	$ 9,463.9	$ 4,239.9	$ 3,742.0	$ 6,454.5	$ 11,313.8	$ 12,432.5	$ 7,104.9	$ 1,055.5	$ 62,040.0
34	Elkhorn Wind Expense ($ x 1000)	$ 1,306.4	$ 1,278.8	$ 1,647.8	$ 2,134.4	$ 1,859.3	$ 1,404.6	$ 1,520.4	$ 2,275.2	$ 2,272.9	$ 1,914.6	$ 1,811.6	$ 1,276.3	$ 20,702.2
35	Neal Hot Springs Expense ($ x 1000)	$ 1,324.1	$ 1,037.8	$ 1,325.5	$ 1,325.3	$ 1,361.1	$ 1,503.0	$ 1,968.7	$ 2,613.2	$ 2,834.7	$ 2,214.5	$ 2,062.2	$ 1,550.4	$ 21,120.7
36	Raft River Geothermal Expense ($ x 1000)	$ 365.4	$ 279.2	$ 420.5	$ 534.9	$ 495.9	$ 442.1	$ 439.5	$ 572.0	$ 631.9	$ 538.7	$ 473.5	$ 374.0	$ 5,567.7
37	Total Expense Excl. PURPA ($ x 1000)	$ 2,995.9	$ 2,595.8	$ 4,408.3	$ 9,213.2	$ 13,180.3	$ 7,589.6	$ 7,670.5	$ 11,914.9	$ 17,053.2	$ 17,100.4	$ 11,452.3	$ 4,256.2	$ 109,430.5
	Surplus Sales													
38	Energy (MWh)	427,655.3	266,951.6	53,216.0	9,169.5	1,987.6	2,905.2	10,547.8	782.9	38.5	24.5	476.0	76,230.0	849,984.8
39	Revenue Including Transmission Expenses ($ x 1000)	$ 6,543.3	$ 2,476.5	$ 669.5	$ 269.0	$ 80.2	$ 87.6	$ 240.6	$ 19.9	$ 1.4	$ 0.8	$ 14.3	$ 1,616.7	$ 12,020.0
40	Transmission Expenses ($ x 1000)	$ 427.7	$ 267.0	$ 53.2	$ 9.2	$ 2.0	$ 2.9	$ 10.5	$ 0.8	$ 0.0	$ 0.0	$ 0.5	$ 76.2	$ 850.0
41	Revenue Excluding Transmission Expenses ($ x 1000)	$ 6,115.7	$ 2,209.6	$ 616.3	$ 259.8	$ 78.3	$ 84.7	$ 230.1	$ 19.1	$ 1.3	$ 0.8	$ 13.8	$ 1,540.5	$ 11,170.0
	Net Hedges													
42	Energy (MWh)	-	-	38,000.0	55,440.0	11,232.0	-	-	-	-	-	-	-	104,672.0
43	Cost($ X 1000)	$ -	$ -	$ 250.0	$ 1,873.2	$ 702.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,825.2
44	Net Power Supply Expenses ($ x 1000)	$ 327.0	$ 5,757.6	$ 10,257.1	$ 26,259.1	$ 30,403.4	$ 17,384.4	$ 14,635.5	$ 20,931.9	$ 31,294.1	$ 28,029.8	$ 17,934.8	$ 7,390.8	$ 210,605.5
45	PURPA ($ x 1000)	$ 17,708.3	$ 18,217.7	$ 23,047.9	$ 25,142.5	$ 24,024.1	$ 17,981.0	$ 16,195.2	$ 16,851.4	$ 15,883.8	$ 13,985.5	$ 15,133.3	$ 13,875.0	$ 218,045.8
46	EIM Benefits													$ 16,886.3
47	Total Net Power Supply Expenses ($ x 1000)	$ 18,035.3	$ 23,975.3	$ 33,305.0	$ 51,401.6	$ 54,427.5	$ 35,365.4	$ 30,830.7	$ 37,783.4	$ 47,177.9	$ 42,015.3	$ 33,068.1	$ 21,265.8	$ 411,764.9
48	Sales at Customer Level (In 000s MWH)	1,033.794	1,091.012	1,265.207	1,548.646	1,616.825	1,436.194	1,123.870	1,039.822	1,167.969	1,311.961	1,248.050	1,129.515	15,012.868
49	Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
50	Unit Cost / MWH (for PCAM)	$17.45	$21.98	$26.32	$33.19	$33.66	$24.62	$27.43	$36.34	$40.39	$32.02	$26.50	$18.83	$27.43
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
51	Portion of Purchased Power considered HL Purchases	0.00%	0.00%	48.42%	38.94%	18.34%	46.29%	48.22%	47.77%	37.53%	25.67%	17.78%	2.06%	
52	Purchased Power HL Price	18.18	12.73	16.94	35.74	47.22	35.33	27.53	28.78	40.16	37.82	34.34	24.26	
53	Portion of Surplus Sales considered HL Surplus Sales	63.17%	60.39%	67.51%	76.25%	82.34%	70.87%	41.49%	76.12%	70.80%	86.08%	73.04%	75.78%	
54	Surplus Sales HL Price	16.87	11.81	15.71	33.16	43.81	32.78	25.55	26.70	37.26	35.09	31.86	22.51	
	Light Load													
55	Portion of Purchased Power considered LL Purchases	0.00%	0.00%	51.58%	61.06%	81.66%	53.71%	51.78%	52.23%	62.47%	74.33%	82.22%	97.94%	
56	Purchased Power LL Price	14.46	6.21	6.96	19.55	27.90	27.31	23.94	24.37	34.38	31.81	28.65	19.65	
57	Portion of Surplus Sales considered LL Surplus Sales	36.83%	39.61%	32.49%	23.75%	17.66%	29.13%	58.51%	23.88%	29.20%	13.92%	26.96%	24.22%	
58	Surplus Sales LL Price	12.61	5.42	6.07	17.05	24.33	23.82	20.87	21.25	29.98	27.74	24.98	17.14	

APPENDIX A

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366

STIPULATION

Exhibit 4

Combined Rate Calculation

April 15, 2020

APCU Combined Rate Calculation
April 2020 - March 2021

Line	**OCTOBER APCU**	
1	Forecast of Normalized Sales (MWh)	15,012,868
2	Total Net Power Supply Expense	$375,586,488
3	October APCU Unit Cost ($/MWh)	$25.02
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	15,012,868
5	Total Net Power Supply Expense	$411,764,934
6	March Forecast Unit Cost ($/MWh)	$27.43
7	Sales Adjusted Forecast Power Cost Change	$36,181,012
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$34,371,961
10	**March Forecast Rate ($/MWh)**	$2.29
11	**Combined Rate ($/MWh)**	$27.31

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366

STIPULATION

Exhibit 5

Revenue Spread

April 15, 2020

Idaho Power Company
Stipulated Revenue Spread
2020 October Update

Line No.		
1	2020 October Update Oregon Jurisdictional Share of Base NPSE = $25.02/MWh x 683,811.053 MWhs =	$ 17,108,953
2	Oregon Allocated EIM Costs	$ 150,390
3	**Proposed October Update APCU Revenue Requirement**	**$ 17,259,343**

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
4	**April 2020 - March 2021 Generation Level Normalized Sales (kWh)**	**736,750,725**	203,714,779	21,359,651	129,187,704	15,957,170	3,308,733	473,684	178,599,571	111,290,414	71,860,761	5,904	967,370	24,984
5	**Class Share of April 2020 - March 2021 Generation Level Normalized Sales (kWh)**	**100%**	27.65%	2.90%	17.53%	2.17%	0.45%	0.06%	24.24%	15.11%	9.75%	0.00%	0.13%	0.00%
6	**2020 October Update Class Allocated Base NPSE**	$ 17,259,343	$ 4,772,283	$ 500,378	$ 3,026,390	$ 373,817	$ 77,511	$ 11,097	$ 4,183,927	$ 2,607,122	$ 1,683,432	$ 138	$ 22,662	$ 585
7	**June 2020 - May 2021 Loss-Adjusted Normalized Sales (kWh)**	**684,994,949**	185,871,153	19,517,431	118,066,056	15,058,811	3,199,934	432,196	168,569,794	107,800,796	65,567,958	5,388	882,636	22,796
8	**Proposed APCU Base Rates for 2020 October Update ($/kWh)**	**0.025196**	**0.025675**	**0.025637**	**0.025633**	**0.024824**	**0.024223**	**0.025675**	**0.024820**	**0.024185**	**0.025675**	**0.025670**	**0.025675**	**0.025675**
9	**Proposed October Update APCU Revenue Requirement**	**$ 17,259,343**	$ 4,772,283	$ 500,378	$ 3,026,390	$ 373,817	$ 77,511	$ 11,097	$ 4,183,927	$ 2,607,122	$ 1,683,432	$ 138	$ 22,662	$ 585

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
10	**Current APCU Base Rates for 2019 October Update ($/kWh) - Order No. 19-189**	**0.025530**	0.026372	0.026342	0.026341	0.025504	0.024880	0.026372	0.025504	0.022731	0.026355	0.026366	0.026372	0.024477
11	**June 2020 - May 2021 Loss-Adjusted Normalized Sales (kWh)**	**684,994,949**	185,871,153	19,517,431	118,066,056	15,058,811	3,199,934	432,196	168,569,794	107,800,796	65,567,958	5,388	882,636	22,796
12	**Base NPSE Recovered under Current APCU Base Rates**	**$ 17,502,504**	$ 4,901,740	$ 514,125	$ 3,109,920	$ 384,065	$ 79,614	$ 11,398	$ 4,299,191	$ 2,450,459	$ 1,728,016	$ 142	$ 23,277	$ 558

Idaho Power Company
Revenue Spread Exhibit for 2020 APCU March Forecast
Stipulated Revenue Spread

Line No.		
1	Oregon Jurisdictional Share of 2020 March Forecast NPSE = $2.29/MWh x 683,811.053 MWhs =	$ 1,565,927

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
2	April 2020 - March 2021 Generation Level Normalized Sales (kWh)	736,750,725	203,714,779	21,359,651	129,187,704	15,957,170	3,308,733	473,684	178,599,571	111,290,414	71,860,761	5,904	967,370	24,984
3	Class Share of April 2020 - March 2021 Generation Level Normalized Sales (kWh)	100%	27.65%	2.90%	17.53%	2.17%	0.45%	0.06%	24.24%	15.11%	9.75%	0.00%	0.13%	0.00%
4	2020 March Forecast Class Allocated NPSE	$ 1,565,927	$ 432,986	$ 45,399	$ 274,582	$ 33,916	$ 7,033	$ 1,007	$ 379,605	$ 236,542	$ 152,737	$ 13	$ 2,056	$ 53
5	June 2020 - May 2021 Loss-Adjusted Normalized Sales (kWh)	684,994,949	185,871,153	19,517,431	118,066,056	15,058,811	3,199,934	432,196	168,569,794	107,800,796	65,567,958	5,388	882,636	22,796
6	Proposed APCU Rates for 2020 March Forecast ($/kWh)	0.00229	0.00233	0.00233	0.00233	0.00225	0.00220	0.00233	0.00225	0.00219	0.00233	0.00233	0.00233	0.00233
7	Proposed March Forecast Revenue Requirement	$ 1,565,927	$ 432,986	$ 45,399	$ 274,582	$ 33,916	$ 7,033	$ 1,007	$ 379,605	$ 236,542	$ 152,737	$ 13	$ 2,056	$ 53

8	APCU Rates for 2019 March Forecast - Order No. 19-189 ($/kWh)	0.00116	0.00118	0.00118	0.00118	0.00114	0.00111	0.00118	0.00114	0.00111	0.00118	0.00118	0.00118	0.00118
9	June 2020 - May 2021 Loss-Adjusted Normalized Sales (kWh)	684,994,949	185,871,153	19,517,431	118,066,056	15,058,811	3,199,934	432,196	168,569,794	107,800,796	65,567,958	5,388	882,636	22,796
10	NPSE Recovered under Current March Forecast Rate	$ 793,835	$ 219,450	$ 23,017	$ 139,231	$ 17,195	$ 3,564	$ 510	$ 192,474	$ 119,955	$ 77,363	$ 6	$ 1,042	$ 27

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2020

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	2020 October Update Proposed Base NPSE Revenue	Total Proposed Base Revenue	2020 October Update Proposed Adjustments to Base Revenue	2020 October Update Base Revenue Percent Change
	Uniform Tariff Rates:										
1	Residential Service	1	13,474	185,871,153	$ 12,071,304	$ 4,901,740	$ 16,973,044	$ 4,772,283	$ 16,843,587	$ (129,457)	(0.76)%
2	Small General Service	7	2,672	19,517,431	$ 1,492,625	$ 514,125	$ 2,006,749	$ 500,378	$ 1,993,002	$ (13,747)	(0.69)%
3	Large General Secondary	9S	938	118,066,056	$ 5,823,517	$ 3,109,920	$ 8,933,436	$ 3,026,390	$ 8,849,906	$ (83,530)	(0.94)%
4	Large General Primary	9P	5	15,058,811	$ 643,029	$ 384,065	$ 1,027,094	$ 373,817	$ 1,016,847	$ (10,248)	(1.00)%
5	Large General Transmission	9T	1	3,199,934	$ 117,393	$ 79,614	$ 197,007	$ 77,511	$ 194,905	$ (2,103)	(1.07)%
6	Dusk to Dawn Lighting	15	0	432,196	$ 94,473	$ 11,398	$ 105,871	$ 11,097	$ 105,570	$ (301)	(0.28)%
7	Large Power Primary	19P	6	168,569,794	$ 5,789,917	$ 4,299,191	$ 10,089,108	$ 4,183,927	$ 9,973,844	$ (115,264)	(1.14)%
8	Large Power Transmission	19T	1	107,800,796	$ 3,769,063	$ 2,450,459	$ 6,219,521	$ 2,607,122	$ 6,376,185	$ 156,664	2.52%
9	Agricultural Irrigation Service	24	2,049	65,567,958	$ 4,563,299	$ 1,728,016	$ 6,291,316	$ 1,683,432	$ 6,246,731	$ (44,585)	(0.71)%
10	Unmetered General Service	40	2	5,388	$ 189	$ 142	$ 331	$ 138	$ 328	$ (4)	(1.13)%
11	Street Lighting	41	26	882,636	$ 121,563	$ 23,277	$ 144,840	$ 22,662	$ 144,225	$ (615)	(0.42)%
12	Traffic Control Lighting	42	8	22,796	$ 1,635	$ 558	$ 2,193	$ 585	$ 2,220	$ 27	1.25%
13	Total Uniform Tariffs		19,182	684,994,949	$ 34,488,007	$ 17,502,504	$ 51,990,511	$ 17,259,343	$ 51,747,350	$ (243,161)	(0.47)%
14	Total Oregon Retail Sales		19,182	684,994,949	$ 34,488,007	$ 17,502,504	$ 51,990,511	$ 17,259,343	$ 51,747,350	$ (243,161)	(0.47)%

Line No	Tariff Description	Current Billed Revenue w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	2020 March Forecast Proposed Revenue	2020 March Forecast Proposed Adjustments to Billed Revenue	2020 Composite APCU Revenue Adjustment	Proposed Total Billed Revenue	2020 Composite APCU Percent Change	Stipulated Revenue Increase Cap (3.96%)	Revenue Requirement Shortfall
	Uniform Tariff Rates:										
1	Residential Service	$ 17,755,085	$ 219,450	$ 17,974,536	$ 432,986	$ 213,536	$ 84,079	$ 18,058,615	0.47%	$ 84,079	$ -
2	Small General Service	$ 2,093,394	$ 23,017	$ 2,116,411	$ 45,399	$ 22,382	$ 8,634	$ 2,125,046	0.41%	$ 8,634	$ -
3	Large General Secondary	$ 9,313,307	$ 139,231	$ 9,452,538	$ 274,582	$ 135,351	$ 51,822	$ 9,504,359	0.55%	$ 51,822	$ -
4	Large General Primary	$ 1,070,491	$ 17,195	$ 1,087,685	$ 33,916	$ 16,722	$ 6,474	$ 1,094,159	0.60%	$ 6,474	$ -
5	Large General Transmission	$ 205,273	$ 3,564	$ 208,837	$ 7,033	$ 3,468	$ 1,366	$ 210,203	0.65%	$ 1,366	$ -
6	Dusk to Dawn Lighting	$ 110,554	$ 510	$ 111,064	$ 1,007	$ 497	$ 195	$ 111,260	0.18%	$ 195	$ -
7	Large Power Primary	$ 10,511,516	$ 192,474	$ 10,703,990	$ 379,605	$ 187,130	$ 71,866	$ 10,775,856	0.67%	$ 71,866	$ -
8	Large Power Transmission	$ 6,479,190	$ 119,955	$ 6,599,145	$ 236,542	$ 116,587	$ 273,251	$ 6,872,396	4.14%	$ 261,326	$ 11,925
9	Agricultural Irrigation Service	$ 6,562,133	$ 77,363	$ 6,639,496	$ 152,737	$ 75,373	$ 30,789	$ 6,670,285	0.46%	$ 30,789	$ -
10	Unmetered General Service	$ 345	$ 6	$ 352	$ 13	$ 6	$ 2	$ 354	0.69%	$ 2	$ -
11	Street Lighting	$ 151,192	$ 1,042	$ 152,234	$ 2,056	$ 1,014	$ 399	$ 152,634	0.26%	$ 399	$ -
12	Traffic Control Lighting	$ 2,287	$ 27	$ 2,314	$ 53	$ 26	$ 53	$ 2,368	2.31%	$ 53	$ -
13	Total Uniform Tariffs	$ 54,254,768	$ 793,835	$ 55,048,602	$ 1,565,927	$ 772,093	$ 528,931	$ 55,577,534	0.96%	$ 517,006	$ 11,925
14	Total Oregon Retail Sales	$ 54,254,768	$ 793,835	$ 55,048,602	$ 1,565,927	$ 772,093	$ 528,931	$ 55,577,534	0.96%		

(1) Updated June 2020-May 2021 Test Year

Idaho Power Company
Revenue Spread Exhibit for 2020 APCU
Stipulated Revenue Spread

Line No.		
1	3.96% Increase Cap - Revenue Requirement Shortfall	$ 11,925

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
2	**April 2020 - March 2021 Generation Level Normalized Sales (kWh)**	**625,460,311**	203,714,779	21,359,651	129,187,704	15,957,170	3,308,733	473,684	178,599,571		71,860,761	5,904	967,370	24,984
3	**Class Share of April 2020 - March 2021 Generation Level Normalized Sales (kWh)**	**100%**	32.57%	3.42%	20.65%	2.55%	0.53%	0.08%	28.55%		11.49%	0.00%	0.15%	0.00%
4	**2020 APCU Class Allocated Revenue Requirement Shortfall**	**$ 11,925**	$ 3,884	$ 407	$ 2,463	$ 304	$ 63	$ 9	$ 3,405		$ 1,370	$ 0	$ 18	$ 0.5
5	**June 2020 - May 2021 Loss-Adjusted Normalized Sales (kWh)**	**577,194,153**	185,871,153	19,517,431	118,066,056	15,058,811	3,199,934	432,196	168,569,794		65,567,958	5,388	882,636	22,796
6	**2020 APCU Revenue Requirement Shortall Rates ($/kWh)**	**0.00002**	**0.00002**	**0.00002**	**0.00002**	**0.00002**	**0.00002**	**0.00002**	**0.00002**		**0.00002**	**0.00002**	**0.00002**	**0.00002**

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2020

Summary of Revenue Impact
Current Base Revenue to Proposed Base Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	2020 October Update Proposed Base NPSE Revenue	Total Proposed Base Revenue	2020 October Update Proposed Adjustments to Base Revenue	2020 October Update Base Revenue Percent Change	1st Pass Adjustment to 2020 October Update Proposed Base NPSE Revenue	1st Pass 2020 October Update Proposed Adjustments to Base Revenue	1st Pass 2020 October Update Base Revenue Percent Change	1st Pass 2020 October Update Proposed Base NPSE Revenue	Revised APCU Rates for 2020 October Update ($/kWh)
	Uniform Tariff Rates:															
1	Residential Service	1	13,474	185,871,153	$ 12,071,304	$ 4,901,740	$ 16,973,044	$ 4,772,283	$ 16,843,587	$ (129,457)	(0.76)%	$ 3,884	$ (125,573)	(0.74)%	$ 4,776,167	0.025696
2	Small General Service	7	2,672	19,517,431	$ 1,492,625	$ 514,125	$ 2,006,749	$ 500,378	$ 1,993,002	$ (13,747)	(0.69)%	$ 407	$ (13,340)	(0.66)%	$ 500,785	0.025658
3	Large General Secondary	9S	938	118,066,056	$ 5,823,517	$ 3,109,920	$ 8,933,436	$ 3,026,390	$ 8,849,906	$ (83,530)	(0.94)%	$ 2,463	$ (81,067)	(0.91)%	$ 3,028,853	0.025654
4	Large General Primary	9P	5	15,058,811	$ 643,029	$ 384,065	$ 1,027,094	$ 373,817	$ 1,016,847	$ (10,248)	(1.00)%	$ 304	$ (9,943)	(0.97)%	$ 374,122	0.024844
5	Large General Transmission	9T	1	3,199,934	$ 117,393	$ 79,614	$ 197,007	$ 77,511	$ 194,905	$ (2,103)	(1.07)%	$ 63	$ (2,040)	(1.04)%	$ 77,574	0.024243
6	Dusk to Dawn Lighting	15	0	432,196	$ 94,473	$ 11,398	$ 105,871	$ 11,097	$ 105,570	$ (301)	(0.28)%	$ 9	$ (292)	(0.28)%	$ 11,106	0.025696
7	Large Power Primary	19P	6	168,569,794	$ 5,789,917	$ 4,299,191	$ 10,089,108	$ 4,183,927	$ 9,973,844	$ (115,264)	(1.14)%	$ 3,405	$ (111,859)	(1.11)%	$ 4,187,332	0.024840
8	Large Power Transmission	19T	1	107,800,796	$ 3,769,063	$ 2,450,459	$ 6,219,521	$ 2,607,122	$ 6,376,185	$ 156,664	2.52%	$ -	$ 144,739	2.33%	$ 2,595,197	0.024074
9	Agricultural Irrigation Service	24	2,049	65,567,958	$ 4,563,299	$ 1,728,016	$ 6,291,316	$ 1,683,432	$ 6,246,731	$ (44,585)	(0.71)%	$ 1,370	$ (43,215)	(0.69)%	$ 1,684,802	0.025696
10	Unmetered General Service	40	2	5,388	$ 189	$ 142	$ 331	$ 138	$ 328	$ (4)	(1.13)%	$ 0	$ (4)	(1.10)%	$ 138	0.025691
11	Street Lighting	41	26	882,636	$ 121,563	$ 23,277	$ 144,840	$ 22,662	$ 144,225	$ (615)	(0.42)%	$ 18	$ (596)	(0.41)%	$ 22,680	0.025696
12	Traffic Control Lighting	42	8	22,796	$ 1,635	$ 558	$ 2,193	$ 585	$ 2,220	$ 27	1.25%	$ 0	$ 27	1.25%	$ 585	0.025675
13	Total Uniform Tariffs		19,182	684,994,949	$ 34,488,007	$ 17,502,504	$ 51,990,511	$ 17,259,343	$ 51,747,350	$ (243,161)	(0.47)%	$ 11,925	$ (243,162)	(0.47)%	$ 17,259,342	
14	Total Oregon Retail Sales		19,182	684,994,949	$ 34,488,007	$ 17,502,504	$ 51,990,511	$ 17,259,343	$ 51,747,350	$ (243,161)	(0.47)%	$ 11,925	$ (243,162)	(0.47)%	$ 17,259,342	

(1) Updated June 2020-May 2021 Test Year

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2020

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Billed Revenue w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	2020 March Forecast Proposed Revenue	2020 March Forecast Proposed Adjustments to Billed Revenue	2020 October Update Proposed Adjustments to Base Revenue	2020 Composite APCU Revenue Adjustment	Proposed Total Billed Revenue	2020 Composite APCU Percent Change
	Uniform Tariff Rates:												
1	Residential Service	1	13,474	185,871,153	$ 17,755,085	$ 219,450	$ 17,974,536	$ 432,986	$ 213,536	$ (125,573)	$ 87,963	$ 18,062,499	0.49%
2	Small General Service	7	2,672	19,517,431	$ 2,093,394	$ 23,017	$ 2,116,411	$ 45,399	$ 22,382	$ (13,340)	$ 9,042	$ 2,125,453	0.43%
3	Large General Secondary	9S	938	118,066,056	$ 9,313,307	$ 139,231	$ 9,452,538	$ 274,582	$ 135,351	$ (81,067)	$ 54,285	$ 9,506,822	0.57%
4	Large General Primary	9P	5	15,058,811	$ 1,070,491	$ 17,195	$ 1,087,685	$ 33,916	$ 16,722	$ (9,943)	$ 6,778	$ 1,094,463	0.62%
5	Large General Transmission	9T	1	3,199,934	$ 205,273	$ 3,564	$ 208,837	$ 7,033	$ 3,468	$ (2,040)	$ 1,429	$ 210,266	0.68%
6	Dusk to Dawn Lighting	15	0	432,196	$ 110,554	$ 510	$ 111,064	$ 1,007	$ 497	$ (292)	$ 204	$ 111,269	0.18%
7	Large Power Primary	19P	6	168,569,794	$ 10,511,516	$ 192,474	$ 10,703,990	$ 379,605	$ 187,130	$ (111,859)	$ 75,271	$ 10,779,262	0.70%
8	Large Power Transmission	19T	1	107,800,796	$ 6,479,190	$ 119,955	$ 6,599,145	$ 236,542	$ 116,587	$ 144,739	$ 261,326	$ 6,860,471	3.96%
9	Agricultural Irrigation Service	24	2,049	65,567,958	$ 6,562,133	$ 77,363	$ 6,639,496	$ 152,737	$ 75,373	$ (43,215)	$ 32,159	$ 6,671,655	0.48%
10	Unmetered General Service	40	2	5,388	$ 345	$ 6	$ 352	$ 13	$ 6	$ (4)	$ 3	$ 354	0.73%
11	Street Lighting	41	26	882,636	$ 151,192	$ 1,042	$ 152,234	$ 2,056	$ 1,014	$ (596)	$ 418	$ 152,652	0.27%
12	Traffic Control Lighting	42	8	22,796	$ 2,287	$ 27	$ 2,314	$ 53	$ 26	$ 27	$ 53	$ 2,368	2.31%
13	Total Uniform Tariffs		19,182	684,994,949	$ 54,254,768	$ 793,835	$ 55,048,602	$ 1,565,927	$ 772,093	$ (243,162)	$ 528,931	$ 55,577,533	0.96%
14	Total Oregon Retail Sales		19,182	684,994,949	$ 54,254,768	$ 793,835	$ 55,048,602	$ 1,565,927	$ 772,093	$ (243,162)	$ 528,931	$ 55,577,533	0.96%

(1) Updated June 2020-May 2021 Test Year