ORDER NO. 19-189

ENTERED May 29 2019

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 350

In the Matter of IDAHO POWER COMPANY, 2019 Annual Power Cost Update.	ORDER

DISPOSITION: STIPULATION ADOPTED; ANNUAL POWER COST UPDATE APPROVED

We adopt the stipulation of the parties 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, 2019.

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, 2018, Idaho Power filed testimony and exhibits for its 2019 APCU, including the October Update which estimated what the normal power supply expenses would be for the 12-month test year, April 2019 through March 2020.[1] Staff filed opening testimony on February 4, 2019. The company subsequently filed the March Forecast on March 25, 2019. The company then filed supplemental 2019 March Forecast testimony.

On May 8, 2019, the company, CUB, and Staff of the Oregon Public Utility Commission filed a stipulation, attached as Appendix A, settling all of the outstanding issues between

[1] Idaho Power/100-109.

the parties. Also on May 8, 2019, the parties filed joint testimony in support of their stipulation.

III. THE 2019 APCU

A. The October Update

Idaho Power's 2019 October Update addressed 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.[2]

The October Update included the company's estimate of incremental costs and benefits associated with participating in the Western Energy Imbalance Market (EIM) to be included in the 2019 APCU. The company proposed to set estimated EIM benefits at $206,511 on an Oregon allocation basis, with costs reflected as $134,175.[3] The company also described progress towards developing a new method for quantifying EIM benefits, and concerns with CAISO's methodology for the calculation of EIM benefits, which the company asserts uses assumptions problematic for hydro-generating utilities like Idaho Power.

Idaho Power's calculations resulted in a cost per unit of $26.11 per megawatt-hour (MWh), a decrease from last year's October Update price of $26.18 per MWh.[4] The decrease is due to lower coal-fired generation, which is driven by increased low-cost natural gas generation. For the 2019 October Update, the company calculated the Oregon jurisdictional share of total NPSE by multiplying the cost per unit of $26.11 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 2019 October Update Oregon jurisdictional share of total NPSE to the NPSE recovery under current approved rates from the 2018 APCU October Update, resulting in an incremental revenue requirement credit of $0.01 million.[5] The company's revenue spread methodology for the 2019 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.[6]

On February 4, 2019, Commission Staff filed opening testimony and exhibits. Staff's testimony raised concerns related to the following: (1) the method used by the company to estimate EIM benefits; (2) the company's compliance with previous Commission

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[2] Idaho Power/100, Blackwell/5-6.
[3] Idaho Power/100, Blackwell/15 and 19.
[4] Idaho Power/100, Blackwell/20.
[5] Idaho Power/200, Blackwell/23-24.
[6] Idaho Power/100, Blackwell/24.

orders regarding Oil, Handling, Administrative General, and Rate Spread; and (3) and the load forecast, natural gas price forecast update, and other general updates.[7] No other party filed opening testimony. No party filed reply testimony.

B. The 2019 March Forecast

On March 25, 2019, Idaho Power filed the 2019 March Forecast component of the APCU. The October Update proposed a revenue decrease of $0.01 million. The company stated that the 2019 composite APCU with both the October Update and March forecast components included would result in a revenue increase of $1.07 million or a 1.94 percent increase.[8]

The company explained that the increase in NPSE for the 2019 March forecast as compared to the October 2019 forecast was largely attributable to higher natural gas prices and electric market prices due to the effects of a significant natural gas pipeline explosion occurring in October 2018. In this testimony, the company also provided an update to the company's forecast of EIM benefits.

In its March Forecast, the company reviewed all the variables for the March Forecast and the following variables changed since the 2019 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 recent water supply forecast from the Northwest River Forecast Center and current reservoir levels, (5) known power purchases and surplus sales made in compliance with the company's energy risk management policy, (6) forward price curve and (7) PURPA contract expenses.[9]

The March Forecast included the same E3 study values for EIM benefit, because the company had not yet completed the development of its methodology for forecasting incremental EIM benefits. The 2019 March Forecast included a unit cost of $27.11 per MWH, compared to the 2018 March Forecast of $25.53 per MWh.

C. The 2019 Supplemental March Forecast Testimony

On April 8, 2019, the company filed supplemental March Forecast testimony which included an update to the forecast of benefits related to EIM participation. The company employed the CAISO methodology for estimating benefit, with customized adjustments. The company proposed to include $11.93 million in system benefits to offset NPSE in the 2019 APCU. With the supplemental testimony, the 2019 March Forecast resulted in a unit cost of $26.83 per MWh and an overall revenue increase of $0.88 million or 1.59 percent, to become effective June 1, 2019.

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[7] Staff/100, Gibbens/1.
[8] Idaho Power/200, Blackwell/2.
[9] Idaho Power/400, Blackwell/4.

IV. THE STIPULATION

On May 8, 2019 the company, Staff and CUB filed a joint stipulation. The parties agree that the Commission should adopt the APCU for Idaho Power subject to certain changes in the current filing as agreed upon in the stipulation. The parties agree 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 should be made effective on June 1, 2019, as permitted by the APCU mechanism, with a revenue requirement increase of $0.74 million, or 1.33 percent overall.

The key provisions of the stipulation are as follows:

1. Staff and CUB find the company level of EIM benefit to be reasonable, but disagree with the methodology utilized; particularly the company's assumptions regarding the value of displacing hydropower dispatch. Staff anticipates the ability to work with the company to better understand its adjustments to the CAISO methodology, gain confidence in the methodology, and identify potential improvements. The stipulating parties reserve their disagreement on the methodology for future resolution. Staff observes that the PCAM true-up will provide an opportunity to review the interaction between the EIM benefit forecast methodology and its impact on ratepayers.

2. No later than September 3, 2019, Idaho Power will hold a workshop with interested parties prior to filing the 2020 APCU to address Bridger Coal Company depreciation expenses.

V. DISCUSSION

We will adopt a stipulation if it is 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 data requests, and participated in settlement conferences. As a result of that review, Staff 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, the parties reached agreement on all unresolved issues and have each executed a stipulation. No person has filed an objection to the stipulation. We therefore find that the record in the case is sufficient to conclude that the company's calculations as modified by the stipulation are correct and conform to Commission precedent.

We have examined the stipulation, the stipulating party testimony, and the pertinent record in the case. 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 2019 October Update, the 2019 March Forecast, the March 2019 Forecast supplemental testimony, Staff's testimony, the stipulating party testimony, and the stipulated modifications to the March Forecast. We therefore conclude that the resulting rates are just and reasonable for resolution of the issues in this docket. The stipulation should be adopted in its entirety.

VI. 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, 2019.

Made, entered, and effective May 29 2019.

Megan W. Decker
Chair

Stephen M. Bloom
Commissioner

Letha Tawney
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 350

In the Matter of IDAHO POWER COMPANY 2019 ANNUAL POWER COST UPDATE	**STIPULATION**

This Stipulation resolves all issues among the parties to Idaho Power Company's ("Idaho Power" or "Company") 2019 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, 2019.

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, 2018, Idaho Power filed testimony and exhibits for the 2019 October Update component of the APCU ("2019 October Update").[2] Pursuant to Order No. 08-238, Idaho Power reviewed all the inputs and provided changes in the 2019 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 2019 October Update was April 2019 through March 2020 and included updates to the above-referenced variables for all Company-owned resources and updated sales and load forecasts.[4] The 2019 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

[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 2019 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 $4.5 million in system EIM benefits as an offset to NPSE in the 2019 October Update.[10] The level of EIM benefits was based on a 2016 EIM benefits study completed by Energy + Environmental Economics ("E3"), which the Company used for the 2019 October Update because it had limited actual data available at the time of filing on which to base an annual forecast of EIM benefits. Idaho Power indicated, however, that it was in the process of developing a methodology to quantify actual benefits achieved through EIM participation, which would serve as the basis for forecasting EIM benefits in the future. The Company's 2019 October Update indicated that the Company intended to keep Staff and parties apprised of the Company's progress towards developing a benefits quantification methodology and that the Company was optimistic that it would be able to provide an updated forecast of EIM benefits to be included in the 2019 APCU during the proceeding, ensuring that rates in effect June 1, 2019, will reflect an appropriate level of

[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/15.

savings associated with EIM participation. The 2019 October Update also included Oregon-allocated EIM costs of $134,175.

7. The filed 2019 October Update resulted in a rate of $26.11 per megawatt-hour ("MWh"), representing a decrease of approximately 0.3 percent relative to last year's October Update rate of $26.18 per MWh.[11]

8. For the 2019 October Update, the Company calculated the Oregon jurisdictional share of total NPSE by multiplying the rate of $26.11 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 2019 October Update Oregon jurisdictional share of total NPSE to the NPSE recovery under current approved rates from the 2018 APCU October Update, resulting in a revenue requirement decrease of approximately $0.01 million.[13]

9. The Company's revenue spread methodology for the 2019 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 was capped at 3 percent above the overall average rate increase on a percentage of total revenue basis. In the 2019 October Update, the overall average rate change as a percentage of total revenue is a decrease of 0.02 percent; therefore, any rate increases applied to individual customer classes was capped at 2.98 percent. Application of the stipulated revenue spread methodology initially

[11] Idaho Power/100, Blackwell/20.

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

[13] Idaho Power/200, Blackwell/23-24.

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

resulted in rate increases for Large Power Transmission Service customers (Tariff Schedule 19T), and Traffic Control Lighting Service customers (Tariff Schedule 42) of 5.58 percent and 4.79 percent, respectively. The Company applied the stipulated rate increase cap of 2.98 percent to these customer classes and reallocated the resulting revenue requirement shortfall among all other customer classes.

10. On October 31, 2018, CUB filed its Notice of Intervention. On December 19, 2018, Administrative Law Judge ("ALJ") Nolan Moser held a prehearing conference 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 2019 APCU prior to June 1, 2019.[15]

11. The Stipulating Parties held an initial workshop on January 22, 2019, to discuss the 2019 October Update filing. Staff and CUB served discovery on Idaho Power and conducted a thorough investigation of the 2019 October Update.

12. On February 4, 2019, 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; and Bridger Coal Company ("BCC") depreciation expenses.

13. CUB did not file Opening Testimony.

14. No party filed cross-answering testimony.

15. On March 25, 2019, Idaho Power filed the 2019 March Forecast component of the APCU ("2019 March Forecast"). The 2019 March Forecast consisted of direct testimony

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

describing the Company's estimate of the expected NPSE for the upcoming water year—April 2019 through March 2020.[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.

16. Idaho Power reviewed all the variables for the March Forecast and the following variables changed since the 2019 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 $37.92 per MWh to $35.03 per MWh, decreased at the Boardman plant ("Boardman") from $27.39 per MWh to $26.57 per MWh, and increased at the Valmy plant from $39.53 per MWh to $58.47 per MWh.[19]

18. The updated natural gas price forecast reflected a decrease of $0.15 per MMBtu, relative to the 2019 October Update. The gas price forecast used for the October

[16] Idaho Power/200-208.

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

[18] Idaho Power/400, Blackwell/4-7.

[19] Idaho Power/200, Blackwell/5-6.

Update for Henry Hub was $3.13 per MMBtu, while the gas price forecast used for the March Forecast for Henry Hub was $2.98 per MMBtu.[20]

19. The Company also updated the hydro forecast.[21] The hydro generation forecasted for this year's March Forecast is 8.4 million MWh compared to 8.5 million MWh in last year's March Forecast, a 1 percent decrease.[22]

20. The March Forecast also included reduced PURPA generation relative to the October Update. The October Update included 343 average megawatts ("aMW") of available PURPA generation, whereas the PURPA generation included in the March Forecast was 338 aMW, a decrease of 5 aMW, or 1.5 percent, since the October Update.[23] Total PURPA expense included in the March Forecast is $220.4 million compared to $221.1 million included in the October Update, a decrease of $0.7 million, or 0.3 percent. PURPA expense included in the 2019 March Forecast is $9.8 million more than PURPA expense included in the 2018 March Forecast, an increase that is primarily due to the addition of six new PURPA projects, which account for an increase in expected generation of 8 aMW since last year's March Forecast.

21. When the 2019 March Forecast was filed, the Company had not completed its development of a methodology for forecasting incremental EIM benefits.[24] Therefore, the EIM benefits included in the 2019 March Forecast were based on the same 2016 E3 study that was used for the 2019 October Update, with a $3.3 million adjustment for expected greenhouse gas benefits, for a total EIM benefit of $7.8 million. The Company indicated, however, that it intended to finalize its proposed methodology for quantifying actual benefits

[20] Idaho Power/200, Blackwell/8.

[21] Idaho Power/200, Blackwell/11-12.

[22] Idaho Power/200, Blackwell/12.

[23] Idaho Power/200, Blackwell/9-10.

[24] Idaho Power/200, Blackwell/17-18.

resulting from the EIM and would supplement the March Forecast testimony with the results of that analysis.

22. The 2019 March Forecast included forecast NPSE of $402.3 million, or $20.3 million more than the 2018 March Forecast of NPSE of $382.0 million.[25] The 2018 March Forecast unit cost per MWh was $25.53 per MWh, compared to this year's March Forecast unit cost of $27.11 per MWh.[26] The overall revenue impact of the combined 2019 October Update and March Forecast is an increase of $1.07 million or 1.94 percent overall. The $1.07 million increase reflects a decrease of $0.15 million in base rate revenues associated with the October Update and a $1.22 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 2018 APCU.[27]

23. On April 8, 2019, Idaho Power filed supplemental March Forecast testimony to update the forecast of benefits related to participation in the EIM.[28] The Company's updated EIM benefits replaced those included in the initial March 25, 2019, filing. Idaho Power proposed to include $11.93 million in system EIM benefits as an offset to NPSE in the 2019 APCU.[29] The Company's supplemental testimony also described in detail the Company's proposed methodology for determining EIM benefits.

24. Because Idaho Power increased the forecasted EIM benefits, the supplemental March Forecast testimony also included updated overall NPSE. Accounting for the increased EIM benefits, the 2019 March Forecast of NPSE is $398.1 million, or $16.2 million more than

[25] Idaho Power/200, Blackwell/14.

[26] Idaho Power/200, Blackwell/26.

[27] Idaho Power/200, Blackwell/28.

[28] Idaho Power/300-307.

[29] Idaho Power/300, Annis/4.

the 2018 March Forecast of NPSE of $382.0 million.[30] Based on the supplemental filing, the 2019 composite APCU (both the October Update and March Forecast components) result in a revenue increase of $0.88 million or a 1.59 percent increase, to become effective June 1, 2019.[31] The 2018 March Forecast unit cost per MWh was $25.53 per MWh, compared to this year's March Forecast unit cost of $26.83 per MWh.[32]

25. The supplemental 2018 March Forecast also included the Company's proposed rate spread used to spread the March Forecast revenue requirement to the various customer classes.[33]

26. Staff and CUB conducted a thorough investigation of the March Forecast, including the supplemental filing.

27. Settlement conferences were held on April 4, 2019, and April 19, 2019. 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

28. EIM Benefits: The Stipulating Parties agree to include $15.12 million in EIM benefits in the 2019 APCU. This amount updates the EIM benefits set forth in the Company's supplemental March Forecast testimony incorporating actual reported EIM results for the entire first quarter of 2019 (as opposed to the supplemental testimony, which used actual data through January 2019 and estimated data for February and March 2019). Based on this update, the Stipulating Parties agree that the Company's forecasted EIM costs and benefits for the 2019 APCU are reasonable. However, the Stipulating Parties do not agree that the methodology used by Idaho Power to calculate the forecasted EIM benefits is

[30] Idaho Power/300, Annis/15.

[31] Idaho Power/300, Annis/15.

[32] Idaho Power/300, Annis/15.

[33] Idaho Power/300, Annis/17-18

reasonable and every party reserves its rights to dispute the methodology used in this case in future proceedings. The parties emphasize that the agreement to include these costs and 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.

29. Based on the agreed-upon EIM benefit update, the Stipulating Parties agree to a revenue requirement increase of $0.74 million or 1.33 percent overall. The Stipulating Parties agree that the Company's allocation methodology conforms to Commission precedent, as reflected in previous APCU stipulations, and should be approved. 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, 2019, as permitted by the APCU mechanism.

31. Idaho Power also agrees to hold a workshop with interested parties prior to filing the 2020 APCU to address Bridger Coal Company depreciation expenses included in the APCU. Idaho Power agrees to hold that workshop no later than September 30, 2019.

32. 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.

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

34. 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.

35. 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.

36. 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.

37. 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.

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

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

STAFF

By: [signature]

Date: 5/7/19

IDAHO POWER

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

STAFF

By: ____________________________

Date:____________________________

IDAHO POWER

By: ____________________________

Date: 5/7/19

OREGON CITIZENS' UTILITY BOARD

By: ____________________________

Date:____________________________

STAFF

By: ______________________________

Date: ______________________________

IDAHO POWER

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: [illegible] for Mike Goetz

Date: 5-7-2019

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 350

STIPULATION

Exhibit 1
Revised October Update NPSE

May 8, 2019

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR APRIL 1, 2019 -- MARCH 31, 2020 (Multiple Gas Prices/90 Hydro Year Conditions)
Repriced Using UE 195 Settlement Methodology - 2019 October Update
AVERAGE

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	892,033.4	962,605.9	933,757.4	695,002.9	535,120.7	519,164.9	510,836.3	442,334.6	647,871.1	797,103.9	794,873.9	822,506.2	8,553,211.1
	Bridger													
2	Energy (MWh)	4,506.1	246.8	21,636.3	175,405.9	208,563.8	86,788.0	60,026.4	110,545.7	157,745.8	134,789.9	78,784.2	36,191.8	1,075,230.6
3	Expense ($ x 1000)	$ 375.7	$ 219.1	$ 987.7	$ 6,384.3	$ 7,543.7	$ 3,310.4	$ 2,397.0	$ 4,193.1	$ 5,768.0	$ 5,001.6	$ 3,054.4	$ 1,538.7	$ 40,773.8
	Boardman													
4	Energy (MWh)	7,013.3	3,951.2	10,926.9	33,299.2	37,712.5	27,206.7	22,262.4	26,374.4	31,328.6	28,045.6	20,704.9	17,005.8	265,831.5
5	Expense ($ x 1000)	$ 218.5	$ 132.8	$ 319.0	$ 910.6	$ 1,026.3	$ 749.6	$ 620.7	$ 728.0	$ 857.9	$ 724.4	$ 544.0	$ 449.8	$ 7,281.5
	Valmy													
6	Energy (MWh)	6,025.1	2,953.3	16,650.0	74,794.5	87,140.6	43,206.2	36,808.4	46,444.1	72,367.6	25,271.0	13,412.3	9,219.1	434,292.3
7	Expense ($ x 1000)	$ 525.7	$ 422.5	$ 842.0	$ 2,565.7	$ 2,924.7	$ 1,648.4	$ 1,461.2	$ 1,747.6	$ 2,499.5	$ 1,129.6	$ 766.0	$ 632.9	$ 17,165.7
	Langley Gulch													
8	Energy (MWh)	191,222.9	197,467.8	190,292.1	198,952.9	199,049.3	193,611.1	195,441.4	192,756.0	202,952.8	193,661.6	171,281.6	193,755.0	2,320,444.3
9	Expense ($ x 1000)	$ 2,611.7	$ 2,607.2	$ 2,528.4	$ 3,276.2	$ 3,249.4	$ 3,130.2	$ 3,307.6	$ 3,747.5	$ 5,006.9	$ 4,461.5	$ 3,653.6	$ 3,480.9	$ 41,061.2
	Danskin													
10	Energy (MWh)	37,565.7	41,924.0	88,012.6	123,234.4	146,973.0	99,690.6	66,039.8	29,429.4	6,766.0	4,125.8	5,810.9	14,472.3	664,044.6
11	Expense ($ x 1000)	$ 879.8	$ 948.1	$ 2,073.8	$ 3,495.5	$ 4,104.5	$ 2,725.1	$ 1,863.7	$ 889.3	$ 264.4	$ 162.5	$ 209.0	$ 444.9	$ 18,060.6
	Bennett Mountain													
12	Energy (MWh)	19,492.8	22,535.2	57,620.9	86,450.0	107,378.1	67,607.4	40,115.4	12,106.4	4,157.8	1,662.9	3,346.3	5,698.5	428,171.7
13	Expense ($ x 1000)	$ 461.8	$ 513.6	$ 1,343.9	$ 2,424.3	$ 2,956.1	$ 1,850.8	$ 1,140.6	$ 364.5	$ 161.8	$ 68.2	$ 125.1	$ 177.2	$ 11,587.9
14	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 689.9	$ 712.5	$ 689.9	$ 712.5	$ 712.5	$ 689.9	$ 712.5	$ 689.9	$ 712.5	$ 711.2	$ 666.0	$ 711.2	$ 8,410.6
	Purchased Power (Excluding CSPP)													
15	Market Energy (MWh)	1,038.5	2,569.9	44,444.9	51,202.2	48,968.7	24,463.2	13,278.2	64,417.4	57,235.6	67,162.7	15,359.0	15,294.9	405,435.2
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	25,076.5	27,293.8	305,682.2
17	Neal Hot Springs Energy (MWh)	15,215.9	11,429.3	11,317.3	9,167.6	9,844.5	12,018.1	16,332.7	18,385.9	20,015.0	18,557.6	17,695.7	17,587.8	177,567.7
18	Raft River Geothermal Energy (MWh)	6,974.0	4,854.7	5,861.8	6,288.1	5,741.9	6,278.0	6,505.3	6,996.5	7,608.9	7,732.9	6,927.9	6,932.1	78,702.0
19	Total Energy Excl. CSPP (MWh)	49,633.0	45,381.1	86,851.5	92,523.3	87,441.1	63,774.7	59,525.6	119,982.2	112,437.1	117,669.9	65,059.2	67,108.6	967,387.0
20	Market Expense ($ x 1000)	$ 18.5	$ 42.2	$ 712.8	$ 1,294.1	$ 1,441.5	$ 663.8	$ 312.4	$ 1,657.3	$ 1,755.8	$ 2,267.9	$ 447.2	$ 367.9	$ 10,981.5
21	Elkhorn Wind Expense ($ x 1000)	$ 1,247.9	$ 1,253.7	$ 1,622.1	$ 1,995.8	$ 1,765.9	$ 1,351.3	$ 1,505.2	$ 2,328.9	$ 2,127.9	$ 1,603.9	$ 1,660.8	$ 1,328.7	$ 19,792.0
22	Neal Hot Springs Expense ($ x 1000)	$ 1,298.8	$ 975.6	$ 1,317.9	$ 1,281.1	$ 1,375.7	$ 1,399.5	$ 1,901.9	$ 2,569.2	$ 2,796.9	$ 2,198.3	$ 2,096.2	$ 1,527.2	$ 20,738.4
23	Raft River Geothermal Expense ($ x 1000)	$ 345.4	$ 240.4	$ 395.0	$ 508.5	$ 464.3	$ 423.0	$ 438.3	$ 565.7	$ 615.3	$ 531.9	$ 476.6	$ 350.5	$ 5,354.8
24	Total Expense Excl. CSPP ($ x 1000)	$ 2,910.6	$ 2,511.9	$ 4,047.7	$ 5,079.4	$ 5,047.4	$ 3,837.6	$ 4,157.9	$ 7,121.2	$ 7,295.9	$ 6,602.1	$ 4,680.8	$ 3,574.2	$ 56,866.6
	Surplus Sales													
25	Energy (MWh)	403,826.5	308,197.9	137,043.4	28,888.5	17,184.8	58,461.5	91,758.2	14,860.0	45,275.5	65,128.3	197,116.5	256,319.6	1,624,060.6
26	Revenue Including Transmission Costs ($ x 1000)	$ 6,524.2	$ 4,591.0	$ 1,992.2	$ 661.9	$ 458.7	$ 1,438.5	$ 1,957.5	$ 346.7	$ 1,259.5	$ 1,994.4	$ 5,205.0	$ 5,591.5	$ 32,021.0
27	Transmission Costs ($ x 1000)	$ 403.8	$ 308.2	$ 137.0	$ 28.9	$ 17.2	$ 58.5	$ 91.8	$ 14.9	$ 45.3	$ 65.1	$ 197.1	$ 256.3	$ 1,624.1
28	Revenue Excluding Transmission Costs ($ x 1000)	$ 6,120.4	$ 4,282.8	$ 1,855.1	$ 633.0	$ 441.5	$ 1,380.0	$ 1,865.8	$ 331.9	$ 1,214.3	$ 1,929.2	$ 5,007.9	$ 5,335.1	$ 30,397.0
29	Net Power Supply Expenses ($ x 1000)	$ 2,553.3	$ 3,785.0	$ 10,977.4	$ 24,215.4	$ 27,123.1	$ 16,561.9	$ 13,795.4	$ 19,149.2	$ 21,352.6	$ 16,931.9	$ 8,691.1	$ 5,674.7	**$ 170,810.9**
30	PURPA ($ x 1000)	$ 18,289.6	$ 19,436.9	$ 23,592.1	$ 25,701.6	$ 23,739.1	$ 18,762.0	$ 17,054.0	$ 16,644.2	$ 15,666.5	$ 12,866.7	$ 15,583.0	$ 13,799.4	$ 221,135.0
31	EIM Benefits													$ 15,120.1
32	Total Net Power Supply Expenses ($ x 1000)	$ 20,842.9	$ 23,221.9	$ 34,569.4	$ 49,917.1	$ 50,862.2	$ 35,323.9	$ 30,849.4	$ 35,793.3	$ 37,019.1	$ 29,798.5	$ 24,274.1	$ 19,474.0	**$ 376,825.835**
33	Sales at Customer Level (In 000s MWH)	1,021.841	1,071.582	1,254.632	1,530.365	1,587.786	1,431.707	1,117.569	1,038.502	1,158.405	1,291.170	1,223.800	1,109.462	14,836.820
34	Hours in Month	720	744	720	744	744	720	744	721	744	744	696	743	8784
35	Unit Cost / MWH (for PCAM)	$20.40	$21.67	$27.55	$32.62	$32.03	$24.67	$27.60	$34.47	$31.96	$23.08	$19.84	$17.55	**$25.40**
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
36	Portion of Purchased Power considered HL Purcha	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	$19.72	$19.07	$19.20	$29.19	$33.20	$29.55	$24.69	$26.96	$32.58	$35.95	$30.40	$25.02	
38	Portion of Surplus Sales considered HL Surplus Sa	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	$18.30	$17.69	$17.82	$27.09	$30.80	$27.41	$22.91	$25.01	$30.23	$33.35	$28.21	$23.21	
	Light Load													
40	Portion of Purchased Power considered LL Purcha:	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	$14.39	$11.69	$10.35	$18.23	$22.67	$22.80	$21.42	$23.51	$27.25	$29.85	$26.81	$22.32	
42	Portion of Surplus Sales considered LL Surplus Sal	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	$12.55	$10.19	$9.02	$15.90	$19.77	$19.89	$18.68	$20.50	$23.77	$26.03	$23.38	$19.46	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 350

STIPULATION

Exhibit 2
Revised March Forecast NPSE

May 8, 2019

Settlement Stipulation
Exhibit No. 2

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2019 -- MARCH 31, 2020 (One Hydro Condition)
Repriced Using UE 195 Settlement Methodology - 2019 March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	1,214,177.5	1,169,085.7	833,524.5	599,345.3	548,513.4	434,986.2	452,285.4	372,904.0	464,806.8	713,750.4	711,968.4	838,047.4	8,353,394.9
	Bridger													
2	Energy (MWh)	-	-	28,608.8	357,583.1	358,788.5	236,935.5	154,621.7	213,707.8	302,459.6	256,559.9	113,418.2	20,982.2	2,043,665.3
3	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ 1,043.7	$ 12,094.4	$ 12,107.3	$ 8,112.4	$ 5,388.9	$ 7,389.4	$ 10,302.8	$ 8,137.1	$ 3,748.5	$ 709.7	$ 69,034.2
4	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 8.0	$ 100.1	$ 100.5	$ 66.3	$ 43.3	$ 59.8	$ 84.7	$ 71.8	$ 31.8	$ 5.9	$ 572.2
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 1,035.7	$ 11,994.3	$ 12,006.8	$ 8,046.1	$ 5,345.6	$ 7,329.5	$ 10,218.1	$ 8,065.2	$ 3,716.8	$ 703.8	$ 68,462.0
6	IPC Share of OHAG Expense ($ x 1000)	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 3,132.2
7	Total Expense ($ x 1000)	$ 261.0	$ 261.0	$ 1,296.7	$ 12,255.3	$ 12,267.9	$ 8,307.1	$ 5,606.6	$ 7,590.6	$ 10,479.1	$ 8,326.2	$ 3,977.8	$ 964.8	$ 71,594.2
	Boardman													
8	Energy (MWh)	2,483.2	1,610.9	20,660.9	39,706.9	39,527.6	32,402.4	27,691.5	30,616.0	39,706.9	31,292.3	15,663.4	7,874.8	289,236.7
9	AURORA Modeled Expense ($ x 1000)	$ 70.0	$ 49.8	$ 534.3	$ 1,004.4	$ 1,000.3	$ 821.9	$ 708.8	$ 777.2	$ 1,004.4	$ 905.7	$ 471.4	$ 249.4	$ 7,597.7
10	AURORA Modeled Handling Expense ($ x 1000)	$ 1.0	$ 0.7	$ 8.5	$ 16.3	$ 16.2	$ 13.3	$ 11.4	$ 12.6	$ 16.3	$ 12.8	$ 6.4	$ 3.2	$ 118.6
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 69.0	$ 49.2	$ 525.8	$ 988.2	$ 984.1	$ 808.6	$ 697.5	$ 764.6	$ 988.2	$ 892.8	$ 465.0	$ 246.2	$ 7,479.1
12	IPC Share of OHAG Expense ($ x 1000)	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 205.3
13	Total Expense ($ x 1000)	$ 86.1	$ 66.3	$ 542.9	$ 1,005.3	$ 1,001.3	$ 825.7	$ 714.6	$ 781.7	$ 1,005.3	$ 910.0	$ 482.1	$ 263.3	$ 7,684.5
	Valmy													
14	Energy (MWh)	-	-	-	51,020.8	55,774.6	11,055.1	-	22,696.3	31,574.0	-	-	-	172,120.8
15	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ -	$ 1,957.5	$ 2,151.2	$ 459.8	$ -	$ 950.3	$ 1,277.3	$ -	$ -	$ -	$ 6,796.1
16	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ 114.8	$ 125.5	$ 24.9	$ -	$ 51.1	$ 71.0	$ -	$ -	$ -	$ 387.3
17	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ 1,842.7	$ 2,025.7	$ 434.9	$ -	$ 899.2	$ 1,206.3	$ -	$ -	$ -	$ 6,408.8
18	IPC Share of OHAG Expense ($ x 1000)	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 3,722.0
19	Usage Charges Paid to IPC ($ x 1000)	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 67.4
20	Total Expense ($ x 1000)	$ 304.5	$ 304.5	$ 304.5	$ 2,147.3	$ 2,330.2	$ 739.5	$ 304.5	$ 1,203.7	$ 1,510.8	$ 304.5	$ 304.5	$ 304.5	$ 10,063.4
	Langley Gulch													
21	Energy (MWh)	29,942.8	168,746.9	186,895.3	199,049.8	198,737.9	193,607.5	180,519.2	181,804.2	197,956.2	174,227.4	155,721.1	148,535.8	2,015,744.0
22	Expense ($ x 1000)	$ 703.4	$ 2,869.3	$ 3,248.8	$ 4,232.3	$ 4,234.7	$ 3,930.4	$ 3,489.0	$ 4,345.1	$ 5,832.7	$ 4,999.1	$ 3,956.8	$ 3,254.4	$ 45,095.9
	Danskin													
23	Energy (MWh)	-	-	28,466.8	65,591.5	60,695.6	32,818.9	19,951.0	3,294.5	1,673.8	-	24.8	97.5	212,614.6
24	Expense ($ x 1000)	$ -	$ -	$ 824.9	$ 2,323.3	$ 2,156.3	$ 1,102.2	$ 633.7	$ 127.9	$ 79.5	$ -	$ 1.0	$ 3.5	$ 7,252.2
	Bennett Mountain													
25	Energy (MWh)	-	-	10,469.1	38,473.4	35,688.5	14,589.3	6,510.2	568.2	477.2	-	-	-	106,775.8
26	Expense ($ x 1000)	$ -	$ -	$ 306.5	$ 1,363.9	$ 1,267.7	$ 493.9	$ 210.0	$ 22.4	$ 23.0	$ -	$ -	$ -	$ 3,687.3
27	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 689.9	$ 712.5	$ 689.9	$ 712.5	$ 712.5	$ 689.9	$ 712.5	$ 689.9	$ 712.5	$ 711.2	$ 666.0	$ 711.2	$ 8,410.6
	Purchased Power (Excluding PURPA)													
28	Market Energy (MWh)	-	-	78,206.6	74,254.3	62,131.0	70,723.1	36,556.2	108,414.5	101,624.4	20,486.2	2,402.0	3,952.4	558,750.8
29	Elkhorn Wind Energy (MWh)	26,404.6	26,527.2	25,227.4	25,865.4	22,886.0	21,221.6	22,494.6	31,195.2	29,677.2	24,216.8	25,076.5	27,293.8	308,086.0
30	Neal Hot Springs Energy (MWh)	15,215.9	11,429.3	11,317.3	9,167.6	9,844.5	12,018.1	16,332.7	18,385.9	20,015.0	18,557.6	17,695.7	17,587.8	177,567.7
31	Raft River Geothermal Energy (MWh)	6,974.0	4,854.7	5,861.8	6,288.1	5,741.9	6,278.0	6,505.3	6,996.5	7,608.9	7,732.9	6,927.9	6,932.1	78,702.0
32	Total Energy Excl. PURPA (MWh)	48,594.5	42,811.1	120,613.2	115,575.5	100,603.3	110,240.8	81,888.8	164,992.0	158,925.5	70,993.4	52,102.2	55,766.1	1,123,106.5
33	Market Expense ($ x 1000)	$ -	$ -	$ 1,854.1	$ 3,412.3	$ 3,002.9	$ 2,769.3	$ 1,054.8	$ 3,229.7	$ 3,882.0	$ 766.6	$ 76.4	$ 99.9	$ 20,148.0
34	Elkhorn Wind Expense ($ x 1000)	$ 1,247.9	$ 1,253.7	$ 1,622.1	$ 1,995.8	$ 1,765.9	$ 1,364.5	$ 1,446.4	$ 2,407.0	$ 2,289.9	$ 1,603.9	$ 1,660.8	$ 1,328.7	$ 19,986.5
35	Neal Hot Springs Expense ($ x 1000)	$ 1,298.8	$ 975.6	$ 1,317.9	$ 1,281.1	$ 1,375.7	$ 1,399.5	$ 1,901.9	$ 2,569.2	$ 2,796.9	$ 2,198.3	$ 2,096.2	$ 1,527.2	$ 20,738.4
36	Raft River Geothermal Expense ($ x 1000)	$ 345.4	$ 240.4	$ 395.0	$ 508.5	$ 464.3	$ 423.0	$ 438.3	$ 565.7	$ 615.3	$ 531.9	$ 476.6	$ 350.5	$ 5,354.8
37	Total Expense Excl. PURPA ($ x 1000)	$ 2,892.1	$ 2,469.7	$ 5,189.1	$ 7,197.6	$ 6,608.7	$ 5,956.3	$ 4,841.4	$ 8,771.7	$ 9,584.1	$ 5,100.7	$ 4,310.1	$ 3,306.2	$ 66,227.7
	Surplus Sales													
38	Energy (MWh)	489,417.3	403,281.0	32,273.2	17,063.9	49,186.7	11,865.1	20,375.2	5,898.8	9,032.7	20,751.6	93,057.4	166,683.0	1,318,885.8
39	Revenue Including Transmission Expenses ($ x 1000)	$ 15,909.4	$ 7,401.9	$ 804.0	$ 878.1	$ 3,188.1	$ 456.6	$ 521.5	$ 168.1	$ 334.5	$ 826.0	$ 3,022.4	$ 4,484.3	$ 37,995.0
40	Transmission Expenses ($ x 1000)	$ 489.4	$ 403.3	$ 32.3	$ 17.1	$ 49.2	$ 11.9	$ 20.4	$ 5.9	$ 9.0	$ 20.8	$ 93.1	$ 166.7	$ 1,318.9
41	Revenue Excluding Transmission Expenses ($ x 1000)	$ 15,420.0	$ 6,998.6	$ 771.7	$ 861.0	$ 3,138.9	$ 444.7	$ 501.2	$ 162.2	$ 325.5	$ 805.2	$ 2,929.4	$ 4,317.6	$ 36,676.1
	Net Hedges													
42	Energy (MWh)	-	-	22,400.0	50,400.0	70,824.0	-	-	-	-	-	-	-	143,624.0
43	Cost($ X 1000)	$ -	$ -	$ 347.2	$ 1,795.4	$ 4,214.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,356.6
44	Net Power Supply Expenses ($ x 1000)	$ (10,483.0)	$ (315.3)	$ 11,978.9	$ 32,171.8	$ 31,654.3	$ 21,600.4	$ 16,011.2	$ 23,370.8	$ 28,901.5	$ 19,546.6	$ 10,768.9	$ 4,490.3	$ 189,696.4
45	PURPA ($ x 1000)	$ 18,142.7	$ 19,200.3	$ 23,471.5	$ 25,324.2	$ 23,342.1	$ 18,523.0	$ 16,375.6	$ 17,500.6	$ 16,357.7	$ 12,846.3	$ 15,541.2	$ 13,745.7	$ 220,371.1
46	EIM Benefits													$ 15,120.1
47	Total Net Power Supply Expenses ($ x 1000)	$ 7,659.7	$ 18,885.0	$ 35,450.4	$ 57,496.1	$ 54,996.4	$ 40,123.4	$ 32,386.8	$ 40,871.4	$ 45,259.2	$ 32,393.0	$ 26,310.1	$ 18,236.0	**$ 394,947.398**
48	Sales at Customer Level (In 000s MWH)	1,021.841	1,071.582	1,254.632	1,530.365	1,587.786	1,431.707	1,117.569	1,038.502	1,158.405	1,291.170	1,223.800	1,109.462	14,836.820
49	Hours in Month	720	744	720	744	744	720	744	720	744	744	696	744	8,784
50	Unit Cost / MWH (for PCAM)	$7.50	$17.62	$28.26	$37.57	$34.64	$28.02	$28.98	$39.36	$39.07	$25.09	$21.50	$16.44	**$26.62**
	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	38.44	23.12	32.99	62.34	76.37	45.51	31.43	32.21	42.60	44.52	37.30	30.70	
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	35.67	21.45	30.61	57.84	70.85	42.22	29.16	29.88	39.52	41.31	34.61	28.49	
	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	31.06	15.64	14.99	35.50	42.04	33.68	26.45	27.58	35.56	34.97	30.63	25.17	
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	27.09	13.64	13.08	30.96	36.66	29.37	23.07	24.05	31.01	30.50	26.71	21.95	

ORDER NO. 19-189

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 350

STIPULATION

Exhibit 3
Revised Combined Rate Calculation

May 8, 2019

APCU Combined Rate Calculation
April 2019 - March 2020

Line			
	OCTOBER APCU		
1	Forecast of Normalized Sales (MWh)		14,836,820
2	Total Net Power Supply Expense	$	376,825,835
3	October APCU Unit Cost ($/MWh)	$	25.40
	MARCH FORECAST		
4	Forecast of Normalized Sales (MWh)		14,836,820
5	Total Net Power Supply Expense	$	394,947,398
6	March Forecast Unit Cost ($/MWh)	$	26.62
7	Sales Adjusted Forecast Power Cost Change	$	18,100,920
8	Portion of Change Allowed		95%
9	Forecast Change Allowed		$17,195,874
10	**March Forecast Rate ($/MWh)**	$	1.16
11	**Combined Rate ($/MWh)**	$	26.56

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 350

STIPULATION

Exhibit 4
Revised Revenue Spread – Revenue Impact

May 8, 2019

Idaho Power Company
Stipulated Revenue Spread
2019 APCU October Update

Line No.		
1	2019 October Update Oregon Jurisdictional Share of Base NPSE = $25.40/MWh x 686,328,238 MWhs =	$ 17,432,737
2	Oregon Allocated EIM Costs	$ 111,328
3	**Proposed October Update APCU Revenue Requirement**	**$ 17,544,065**

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 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**739,054,443**	200,415,527	20,337,588	128,830,884	16,293,835	2,945,056	474,418	178,538,874	116,192,364	74,019,084	5,904	976,356	24,553
5	**Class Share of April 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**100%**	27.12%	2.75%	17.43%	2.20%	0.40%	0.06%	24.16%	15.72%	10.02%	0.00%	0.13%	0.00%
6	**2019 October Update Class Allocated Base NPSE**	$ 17,544,065	$ 4,757,570	$ 482,784	$ 3,058,256	$ 386,792	$ 69,911	$ 11,262	$ 4,238,250	$ 2,758,236	$ 1,757,104	$ 140	$ 23,177	$ 583
7	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**687,203,565**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
8	**Proposed APCU Base Rates for 2019 October Update ($/kWh)**	**0.025530**	**0.026017**	**0.025988**	**0.025987**	**0.025162**	**0.024546**	**0.026017**	**0.025161**	**0.024521**	**0.026001**	**0.026012**	**0.026017**	**0.026018**
9	**Proposed October Update APCU Revenue Requirement**	**$ 17,544,065**	$ 4,757,570	$ 482,784	$ 3,058,256	$ 386,792	$ 69,911	$ 11,262	$ 4,238,250	$ 2,758,236	$ 1,757,104	$ 140	$ 23,177	$ 583

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 2018 October Update ($/kWh) - Order No. 18-170**	**0.026284**	0.027402	0.027429	0.027428	0.025801	0.025886	0.027439	0.026514	0.021840	0.027425	0.027433	0.022934	0.022111
11	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**687,203,565**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
12	**Base NPSE Recovered under Current APCU Base Rates**	**$ 18,027,784**	$ 5,010,833	$ 509,563	$ 3,227,913	$ 396,620	$ 73,730	$ 11,877	$ 4,466,172	$ 2,456,630	$ 1,853,372	$ 148	$ 20,430	$ 495

ORDER NO. 19-189

Idaho Power Company
Revenue Spread Exhibit for 2019 APCU March Forecast
Stipulated Revenue Spread

Line No.		
1	**Oregon Jurisdictional Share of 2019 March Forecast NPSE = $1.16/MWh x 686,328.238 MWhs =**	**$ 796,141**

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 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**739,054,443**	200,415,527	20,337,588	128,830,884	16,293,835	2,945,056	474,418	178,538,874	116,192,364	74,019,084	5,904	976,356	24,553
3	**Class Share of April 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**100%**	27.12%	2.75%	17.43%	2.20%	0.40%	0.06%	24.16%	15.72%	10.02%	0.00%	0.13%	0.00%
4	**2019 March Forecast Class Allocated NPSE**	$ 796,141	$ 215,896	$ 21,909	$ 138,782	$ 17,552	$ 3,173	$ 511	$ 192,330	$ 125,167	$ 79,736	$ 6	$ 1,052	$ 26
5	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**687,203,565**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
6	**Proposed APCU Rates for 2019 March Forecast ($/kWh)**	**0.001159**	**0.001181**	**0.001179**	**0.001179**	**0.001142**	**0.001114**	**0.001181**	**0.001142**	**0.001113**	**0.001180**	**0.001180**	**0.001181**	**0.001181**
7	**Proposed March Forecast Revenue Requirement**	**$ 796,141**	$ 215,896	$ 21,909	$ 138,782	$ 17,552	$ 3,173	$ 511	$ 192,330	$ 125,167	$ 79,736	$ 6	$ 1,052	$ 26

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)
8	**APCU Rates for 2018 March Forecast - Order No. 18-170 ($/kWh)**	**(0.00062)**	**(0.000630)**	**(0.000630)**	**(0.000630)**	**(0.000610)**	**(0.000595)**	**(0.000631)**	**(0.000609)**	**(0.000594)**	**(0.000630)**	**(0.000630)**	**(0.000631)**	**(0.000630)**
9	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**687,203,565**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
10	**NPSE Recovered under Current March Forecast Rate**	**$ (424,940)**	$ (115,142)	$ (11,709)	$ (74,173)	$ (9,380)	$ (1,694)	$ (273)	$ (102,627)	$ (66,775)	$ (42,588)	$ (3)	$ (562)	$ (14)

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

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	Proposed Base NPSE Revenue	Total Proposed Base Revenue	Proposed Adjustments to Base Revenue	Percent Change Base to Base Revenue
	Uniform Tariff Rates:										
1	Residential Service	1	13,373	182,860,882	$ 12,912,980	$ 5,010,833	$17,923,813	$ 4,757,570	$ 17,670,550	$ (253,263)	(1.41)%
2	Small General Service	7	2,597	18,577,243	1,513,267	509,563	2,022,830	482,784	1,996,052	(26,779)	(1.32)%
3	Large General Secondary	9S	952	117,685,671	6,339,412	3,227,913	9,567,325	3,058,256	9,397,667	(169,658)	(1.77)%
4	Large General Primary	9P	5	15,372,234	727,274	396,620	1,123,893	386,792	1,114,065	(9,828)	(0.87)%
5	Large General Transmission	9T	1	2,848,217	118,803	73,730	192,533	69,911	188,714	(3,819)	(1.98)%
6	Dusk to Dawn Lighting	15	0	432,863	96,490	11,877	108,367	11,262	107,752	(615)	(0.57)%
7	Large Power Primary	19P	6	168,443,209	6,508,337	4,466,172	10,974,509	4,238,250	10,746,587	(227,922)	(2.08)%
8	Large Power Transmission	19T	1	112,485,084	4,359,654	2,456,630	6,816,284	2,758,236	7,117,890	301,606	4.42%
9	Agricultural Irrigation Service	24	2,025	67,579,536	4,986,957	1,853,372	6,840,329	1,757,104	6,744,061	(96,268)	(1.41)%
10	Unmetered General Service	40	2	5,388	248	148	395	140	388	(8)	(1.94)%
11	Street Lighting	41	26	890,836	124,551	20,430	144,981	23,177	147,728	2,747	1.89%
12	Traffic Control Lighting	42	8	22,402	1,680	495	2,175	583	2,263	88	4.02%
13	Total Uniform Tariffs		18,996	687,203,565	$ 37,689,651	$18,027,784	$55,717,436	$17,544,065	$ 55,233,716	$ (483,719)	(0.87)%
14	Total Oregon Retail Sales		18,996	687,203,565	$ 37,689,651	$18,027,784	$55,717,436	$17,544,065	$ 55,233,716	$ (483,719)	(0.87)%

Line No	Tariff Description	Current Billed Revenue w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	Proposed March Forecast Revenue	Proposed Adjustments to March Forecast Revenue	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Percent Change Billed to Billed Revenue	Stipulated Revenue Increase Cap (4.33%)	Revenue Requirement Shortfall
	Uniform Tariff Rates:										
1	Residential Service	$ 17,981,868	$ (115,142)	$17,866,726	$ 215,896	$ 331,038	$ 77,775	$17,944,501	0.44%	$ 77,775	$ -
2	Small General Service	2,022,821	(11,709)	2,011,112	21,909	33,618	6,839	2,017,950	0.34%	6,839	-
3	Large General Secondary	9,567,264	(74,173)	9,493,091	138,782	212,955	43,298	9,536,389	0.46%	43,298	-
4	Large General Primary	1,123,886	(9,380)	1,114,506	17,552	26,932	17,104	1,131,610	1.53%	17,104	-
5	Large General Transmission	192,531	(1,694)	190,837	3,173	4,867	1,048	191,885	0.55%	1,048	-
6	Dusk to Dawn Lighting	108,367	(273)	108,094	511	784	169	108,263	0.16%	169	-
7	Large Power Primary	10,974,422	(102,627)	10,871,795	192,330	294,956	67,035	10,938,829	0.62%	67,035	-
8	Large Power Transmission	6,816,226	(66,775)	6,749,451	125,167	191,942	493,548	7,242,999	7.31%	292,251	201,297
9	Agricultural Irrigation Service	6,840,294	(42,588)	6,797,706	79,736	122,325	26,056	6,823,762	0.38%	26,056	-
10	Unmetered General Service	395	(3)	392	6	10	2	394	0.54%	2	-
11	Street Lighting	144,981	(562)	144,419	1,052	1,613	4,360	148,779	3.02%	4,360	-
12	Traffic Control Lighting	2,175	(14)	2,161	26	41	128	2,289	5.93%	94	35
13	Total Uniform Tariffs	$ 55,775,229	$ (424,940)	$55,350,290	$ 796,141	$ 1,221,080	$ 737,361	$56,087,651	1.33%	$ 536,030	$ 201,332
14	Total Oregon Retail Sales	$ 55,775,229	$ (424,940)	$55,350,290	$ 796,141	$ 1,221,080	$ 737,361	$56,087,651	1.33%		

(1) Updated June 2019-May 2020 Test Year

Idaho Power Company
Revenue Spread Exhibit for 2019 APCU
Stipulated Revenue Spread

Line No.		
1	4.33% Increase Cap - Revenue Requirement Shortfall	$ 201,332

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 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**622,837,526**	200,415,527	20,337,588	128,830,884	16,293,835	2,945,056	474,418	178,538,874		74,019,084	5,904	976,356	
3	**Class Share of April 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**100%**	32.18%	3.27%	20.68%	2.62%	0.47%	0.08%	28.67%		11.88%	0.00%	0.16%	
4	**2019 APCU Class Allocated Revenue Requirement Shortfall**	**$ 201,332**	$ 64,784	$ 6,574	$ 41,644	$ 5,267	$ 952	$ 153	$ 57,712		$ 23,927	$ 2	$ 316	
5	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**574,696,079**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209		67,579,536	5,388	890,836	
6	**2019 APCU Revenue Requirement Shortall Rates ($/kWh)**	**0.000350**	**0.000354**	**0.000354**	**0.000354**	**0.000343**	**0.000334**	**0.000354**	**0.000343**		**0.000354**	**0.000354**	**0.000354**	

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

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	Proposed Base NPSE Revenue	Total Proposed Base Revenue	Proposed Adjustments to Base Revenue	Percent Change Base to Base Revenue	1st Pass Adjustment to Proposed Base NPSE Revenue	1st Pass Proposed Adjustments to Base Revenue	1st Pass Percent Change Base to Base Revenue	1st Pass Proposed Base NPSE Revenue	**Revised APCU Rates for 2019 October Update ($/kWh)**
	Uniform Tariff Rates:															
1	Residential Service	1	13,373	182,860,882	$ 12,912,980	$ 5,010,833	$ 17,923,813	$ 4,757,570	$ 17,670,550	$ (253,263)	(1.41)%	$ 64,784	$ (188,479)	(1.05)%	$ 4,822,354	**0.026372**
2	Small General Service	7	2,597	18,577,243	1,513,267	509,563	2,022,830	482,784	1,996,052	(26,779)	(1.32)%	6,574	(20,205)	(1.00)%	489,359	**0.026342**
3	Large General Secondary	9S	952	117,685,671	6,339,412	3,227,913	9,567,325	3,058,256	9,397,667	(169,658)	(1.77)%	41,644	(128,013)	(1.34)%	3,099,900	**0.026341**
4	Large General Primary	9P	5	15,372,234	727,274	396,620	1,123,893	386,792	1,114,065	(9,828)	(0.87)%	5,267	(4,561)	(0.41)%	392,059	**0.025504**
5	Large General Transmission	9T	1	2,848,217	118,803	73,730	192,533	69,911	188,714	(3,819)	(1.98)%	952	(2,867)	(1.49)%	70,863	**0.024880**
6	Dusk to Dawn Lighting	15	0	432,863	96,490	11,877	108,367	11,262	107,752	(615)	(0.57)%	153	(462)	(0.43)%	11,415	**0.026372**
7	Large Power Primary	19P	6	168,443,209	6,508,337	4,466,172	10,974,509	4,238,250	10,746,587	(227,922)	(2.08)%	57,712	(170,209)	(1.55)%	4,295,963	**0.025504**
8	Large Power Transmission	19T	1	112,485,084	4,359,654	2,456,630	6,816,284	2,758,236	7,117,890	301,606	4.42%	-	100,309	1.47%	2,556,939	**0.022731**
9	Agricultural Irrigation Service	24	2,025	67,579,536	4,986,957	1,853,372	6,840,329	1,757,104	6,744,061	(96,268)	(1.41)%	23,927	(72,342)	(1.06)%	1,781,031	**0.026355**
10	Unmetered General Service	40	2	5,388	248	148	395	140	388	(8)	(1.94)%	2	(6)	(1.45)%	142	**0.026366**
11	Street Lighting	41	26	890,836	124,551	20,430	144,981	23,177	147,728	2,747	1.89%	316	3,062	2.11%	23,493	**0.026372**
12	Traffic Control Lighting	42	8	22,402	1,680	495	2,175	583	2,263	88	4.02%	-	53	2.44%	548	**0.024477**
13	Total Uniform Tariffs		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,544,065	$ 55,233,716	$ (483,719)	(0.87)%	$ 201,332	$ (483,719)	(0.87)%	$ 17,544,065	
14	Total Oregon Retail Sales		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,544,065	$ 55,233,716	$ (483,719)	(0.87)%	$ 201,332	$ (483,719)	(0.87)%	$ 17,544,065	

(1) Updated June 2019-May 2020 Test Year

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

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	Proposed March Forecast Revenue	Proposed Adjustments to March Forecast Revenue	Proposed Adjustments to Base Revenue	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:												
1	Residential Service	1	13,373	182,860,882	$ 17,981,868	$ (115,142)	$ 17,866,726	$ 215,896	$ 331,038	$ (188,479)	$ 142,559	$ 18,009,285	0.80%
2	Small General Service	7	2,597	18,577,243	2,022,821	(11,709)	2,011,112	21,909	33,618	(20,205)	13,413	2,024,525	0.67%
3	Large General Secondary	9S	952	117,685,671	9,567,264	(74,173)	9,493,091	138,782	212,955	(128,013)	84,942	9,578,033	0.89%
4	Large General Primary	9P	5	15,372,234	1,123,886	(9,380)	1,114,506	17,552	26,932	(4,561)	22,371	1,136,877	2.01%
5	Large General Transmission	9T	1	2,848,217	192,531	(1,694)	190,837	3,173	4,867	(2,867)	2,000	192,837	1.05%
6	Dusk to Dawn Lighting	15	0	432,863	108,367	(273)	108,094	511	784	(462)	322	108,416	0.30%
7	Large Power Primary	19P	6	168,443,209	10,974,422	(102,627)	10,871,795	192,330	294,956	(170,209)	124,747	10,996,542	1.15%
8	Large Power Transmission	19T	1	112,485,084	6,816,226	(66,775)	6,749,451	125,167	191,942	100,309	292,251	7,041,702	4.33%
9	Agricultural Irrigation Service	24	2,025	67,579,536	6,840,294	(42,588)	6,797,706	79,736	122,325	(72,342)	49,983	6,847,689	0.74%
10	Unmetered General Service	40	2	5,388	395	(3)	392	6	10	(6)	4	396	1.02%
11	Street Lighting	41	26	890,836	144,981	(562)	144,419	1,052	1,613	3,062	4,676	149,095	3.24%
12	Traffic Control Lighting	42	8	22,402	2,175	(14)	2,161	26	41	53	94	2,255	4.33%
13	Total Uniform Tariffs		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (483,719)	$ 737,361	$ 56,087,651	1.33%
14	Total Oregon Retail Sales		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (483,719)	$ 737,361	$ 56,087,651	1.33%

(1) Updated June 2019-May 2020 Test Year