ORDER NO. 25-194

ENTERED May 22 2025

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 444

In the Matter of IDAHO POWER COMPANY, 2025 Annual Power Cost Update.	ORDER

DISPOSITION: STIPULATION ADOPTED

In this order, we adopt the stipulation entered into by Idaho Power Company, Staff of the Public Utility Commission of Oregon, and the Oregon Citizens' Utility Board (CUB) (collectively, the stipulating parties) resolving all issues in this docket.

I. BACKGROUND

On October 31, 2024, Idaho Power filed its 2025 Annual Power Cost Update (APCU). Through the APCU, Idaho Power annually updates its net power supply expense (NPSE) included in rates, effective June 1. The APCU has two parts, an October update and March forecast.[1] The October update establishes the prospective base or normalized level of NPSE for an April through March test period. The March forecast contains Idaho Power's forecast of expected NPSE over the same test period.

Idaho Power's 2025 October update resulted in a cost per unit of $33.66 per megawatt-hour (MWh). In testimony, Staff proposed certain adjustments to Idaho Power's calculations. CUB did not file opening testimony. Idaho Power filed reply testimony in response to Staff's testimony on February 26, 2025. The company agreed with Staff's proposed adjustment to coal expenses but disagreed with the recommended EIM benefit adjustments and proposed PURPA expense changes.

On March 24, 2025, Idaho Power filed the March forecast, reflecting changes to: fuel prices and transportation costs; forced outage rates; heat rates; forecast of normalized sales and load; forecast of hydro generation from stream flow conditions using the most recent water supply forecast and current reservoir levels; known power purchases and surplus sales made in compliance with the company's Energy Risk Management Policy; forward price curve; and PURPA contract expenses. Idaho Power calculated a March

[1] Adjustments from the October update are reflected in each schedule's base rates. Adjustments from the March forecast are reflected in Idaho Power Schedule 55.

forecast cost per unit of $35.47 per MWh. The forecast demonstrated that combining the 2025 October update and 2025 March forecast resulted in an overall proposed revenue decrease of approximately 1.69 percent, or $1.1 million.

II. STIPULATION

The stipulating parties filed a joint stipulation on May 5, 2025. The stipulating parties agree to a revenue requirement decrease of $1.8 million or 2.62 percent overall. They explain that this represents the company's filed revenue requirement, with adjustments related to EIM benefits and PURPA expenses.

For EIM benefits, the stipulating parties agree to increase system-wide EIM benefits by $2.4 million, compared to the 2025 March forecast, resulting in an increase of $0.1 million Oregon-allocated EIM benefits in the 2025 APCU. The stipulating parties also agree to reduce system-wide PURPA expenses by $12.7 million, resulting in an Oregon-allocated reduction of $0.5 million.

The stipulating parties note that they do not necessarily agree on the methodology for these adjustments but agree that Idaho Power's forecasted EIM benefits and PURPA expenses for the 2025 APCU are reasonable.

The stipulating parties also agree to certain terms for future APCU filings. First, they agree to Idaho Power's proposal to remove the adjustment to reprice the AURORA modeling-generated volumes of purchased power and surplus sales with an average forward electric price curve. They explain that applying the repricing adjustment in this docket would have resulted in a combined increase of 3.01 percent, compared to the combined decrease of 1.69 percent using AURORA-generated prices.[2]

Additionally, Idaho Power will file a report on certain hedge transactions as addressed in the stipulation, with the first report included in the next APCU October Update. The stipulating parties agree to hold workshops to increase transparency regarding Idaho Power's hedging practices and determine whether changes in Idaho Power's hedging modeling as a part of the next APCU may improve the accuracy of the company's hedging forecasts. Idaho Power will address this condition as part of its 2026 APCU October Update.

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[2] *See*, Idaho Power/100, Brady/15-18. Order No. 08-238 states that the output of the AURORA model should be used to determine net power supply average dispatch cost for normal loads and average stream flow conditions, and the wholesale electric prices for purchased power and surplus sales determined by the AURORA model should be replaced with an average forward electric price curve. Idaho Power proposed to remove the repricing requirement because the application of a different price to the purchase and sale volumes outside of the simulation results in an NPSE value that no longer reconciles to the economic dispatch of resources.

III. RESOLUTION

Under OAR 860-001-0350, the Commission may adopt, reject, or propose to modify a stipulation. In reviewing a stipulation, we determine whether the overall result of the stipulation results in fair, reasonable, and just rates. Stipulating parties must present evidence that the stipulation is in accord with public interest and results in just and reasonable rates. We reviewed the terms of the stipulation, the joint supporting brief, and supporting testimony. We find that the stipulation represents a reasonable and appropriate resolution of this docket and that it will result in fair, just, and reasonable rates. Accordingly, we adopt the stipulation in its entirety.

IV. 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, filed on May 5, 2025, attached as Appendix A, is adopted.

2. Idaho Power Company must file new tariffs consistent with this order, reflecting the terms of the stipulation, to be effective June 1, 2025.

Made, entered, and effective May 22 2025.

Letha Tawney Commissioner	**Les Perkins** 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 444

In the Matter of IDAHO POWER COMPANY 2025 Annual Power Cost Update.	**STIPULATION**

This Stipulation resolves all issues among the parties to Idaho Power Company's ("Idaho Power" or "Company") 2025 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, 2025.

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] *In 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 mechanism, to become effective on June 1 of each year.

3. On October 31, 2024, Idaho Power filed testimony and exhibits for the 2025 October Update component of the APCU ("2025 October Update").[2] Pursuant to Order No. 08-238, Idaho Power reviewed all the inputs and provided changes in the 2025 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") contract expenses; and (9) the Oregon state allocation factor.[3]

4. The test period for the 2025 October Update was April 2025 through March 2026 and included updates to the above-referenced variables for all Company-owned resources and updated sales and load forecasts.[4] The 2025 October Update specifically accounted for changes in coal and natural gas prices, generation and expenses related to contracts entered into pursuant to PURPA, new resources, normalized system load, and hydro modeling.[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]

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

[3] Idaho Power/100, Brady/5.

[4] Idaho Power/100, Brady/2-3, 5.

[5] Idaho Power/100, Brady/5-15.

[6] Idaho Power/100, Brady/6-8. Per the terms of the 2016 APCU settlement stipulation, 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 the Bridger and Valmy plants. *In re Idaho Power Company's 2016 Annual Power Cost Update*, Docket No. UE 301, Stipulation at 7 (May 11, 2016). The Company then separately accounted for its proportional share of the total OHAG expense incurred at both plants. Per the terms of the 2017 APCU settlement stipulation, Idaho Power's

6. In the October Update, the Company proposed a modification to the pricing of purchased power and surplus sales. Order No. 08-238 requires Idaho Power to re-price the AURORA-generated volumes of purchased power and surplus sales with a forward-based price curve using the Mid-Columbia ("Mid-C") hub, using a one-year average of the daily Mid-C forward price curves. Beginning with this year's APCU filing, Idaho Power proposed to remove the requirement to reprice the AURORA-generated volumes of purchased power and surplus sales and instead apply the AURORA-generated dispatch price.[7] Removing the repricing adjustment reduced the Company's requested increase in the October Update by 4.98 percent.[8]

7. Idaho Power proposed removing the repricing adjustment because AURORA determines the generation volumes of each resource, as well as purchases and sales, based on the AURORA-calculated dispatch price (or market price) of the respective resource, and applying a different price to the purchase and sale volumes outside of the simulation results in an NPSE value that does not reconcile to the economic dispatch of resources.[9] While this disconnect has existed since the implementation of the repricing adjustment, the combination of increased Mid-C forward market prices compared to AURORA-calculated prices as well

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proportional share of total OHAG expenses incurred at both of the coal-fired plants were 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. *In re Idaho Power Company's 2017 Annual Power Cost Update*, Docket No. UE 314, Stipulation at 7 (Apr. 28, 2017). However, consistent with the 2024 March Forecast, Idaho Power updated the OHAG forecast at Bridger using the 2021-2023 historical average of actual OHAG costs, with a growth rate equal to the 2022-2023 historical average growth rate. The Company excluded the growth rates prior to 2022 due to the change in OHAG beginning in 2021. Starting in 2021, OHAG moved from a positive to a negative number, which is the result of an increase in revenue from fly ash sales. *In re Idaho Power Company's 2024 Annual Power Cost Update*, Docket No. UE 425, March Forecast at 6 (Idaho Power/300, Brady/6 (Mar. 25, 2024)). Idaho Power also accounted for revenues received from or expenses paid to NV Energy (its ownership partner in the Valmy plant) for use of the Company's unused capacity or the Company's use of NV Energy's unused capacity.

[7] Idaho Power/100, Brady/15-18.

[8] Idaho Power/100, Brady/17.

[9] Idaho Power/100, Brady/16-17.

as increased net purchases has resulted in higher impacts to NPSE due to repricing over the last few years.[10]

8. The 2025 October Update also included the Company's estimate of benefits associated with participation in the Western Energy Imbalance Market ("EIM").[11] For the 2025 October Update, Idaho Power proposed to include $21.2 million in system EIM benefits, $0.85 million Oregon-allocated, as an offset to NPSE.[12]

9. The filed 2025 October Update resulted in a rate of $33.66 per megawatt-hour ("MWh"), representing an increase of $4.12 relative to last year's October Update rate of $29.54 per MWh.[13]

10. For the 2025 October Update, the Company calculated the Oregon jurisdictional share of total NPSE by multiplying the rate of $33.66 per MWh by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April through March test period.[14] Idaho Power then calculated the incremental Oregon jurisdictional NPSE by comparing the 2025 October Update Oregon jurisdictional share of total NPSE to the NPSE recovery under current approved rates from the 2024 APCU October Update, resulting in a revenue requirement increase of approximately $2.65 million.[15]

11. The Company's revenue spread methodology for the 2025 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.[16] In addition, consistent with the

[10] Idaho Power/100, Brady/17.

[11] Idaho Power/100, Brady/18-23.

[12] Idaho Power/100, Brady/18.

[13] Idaho Power/100, Brady/26.

[14] Idaho Power/100, Brady/28.

[15] Idaho Power/100, Brady/28.

[16] Idaho Power/100, Brady/29; Idaho Power/108.

stipulation from the 2018 APCU, any rate increase 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. However, the cap is not applicable for the 2025 APCU.

12. On November 8, 2024, CUB filed its Notice of Intervention.

13. On November 20, 2024, Idaho Power filed a stipulated proposed procedural schedule that would allow the Public Utility Commission of Oregon ("Commission") to issue an order on Idaho Power's 2025 APCU prior to June 1, 2025.[17] Administrative Law Judge Sarah Spruce adopted that schedule with a minor modification to the target order date.[18]

14. The Stipulating Parties held an initial workshop on January 8, 2025, to discuss the 2025 October Update filing. Staff and CUB served discovery on Idaho Power and conducted a thorough investigation of the 2025 October Update.

15. On January 29, 2025, Staff filed Opening Testimony.[19] Staff's testimony addressed the Company's natural gas forecasts, hydro modeling, revenue requirement and rate impact, system load, rate spread, NPSE, PURPA and non-PURPA contracts, EIM benefits, participation in the Extended Day Ahead Market, coal costs, and batteries issues.

16. CUB did not file Opening Testimony.

17. Idaho Power filed Reply Testimony on February 26, 2025.[20]

18. On March 24, 2025, Idaho Power filed the 2025 March Forecast component of the APCU ("2025 March Forecast"). The 2025 March Forecast consisted of direct testimony describing the Company's estimate of the expected NPSE for the upcoming water year—April 2025 through March 2026.[21] Order No. 08-238 calls for the March Forecast to update

[17] Idaho Power Company's Proposed Schedule (Nov. 20, 2024).

[18] Memorandum Establishing Procedural Schedule at 1 (Dec. 2, 2024).

[19] Staff/100-101; Staff/200-202; Staff/300-303; Staff/400-402; Staff/500-503; Staff/600-604.

[20] Idaho Power/200.

[21] Idaho Power/300-308.

the following variables: fuel prices, transportation costs, wheeling expenses, planned outages and equivalent forced outage rates, heat rates, forecast of normalized sales and loads updated for known 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.

19. Idaho Power reviewed all the variables for the March Forecast and the following variables changed since the 2025 October Update: (1) fuel prices and transportation costs; (2) forced outage rates; (3) heat rates; (4) forecast of normalized sales and load; (5) forecast of hydro generation from stream flow conditions using the most recent water supply forecast and current reservoir levels; (6) known power purchases and surplus sales made in compliance with the Company's Energy Risk Management Policy; (7) forward price curve; and (8) PURPA contract expenses.[22]

20. The fuel prices were updated to reflect changes in forecast natural gas and coal costs.[23] Total coal fuel expense included in the 2025 March Forecast is $58.2 million, compared to $58.6 million in the 2025 October Update, a decrease of 1 percent. Coal-fired generation also decreased as compared to the October Update, from 1.5 million MWh to 1.4 million MWh, or approximately 9 percent. Forecast coal-fired generation decreased 9 percent from the October Update primarily due to the relative decrease in economics compared to natural gas and market purchases throughout the APCU test year.[24]

21. The updated natural gas price forecast reflected a decrease relative to the 2025 October Update. The gas price forecast used for the March Forecast for Henry Hub was

[22] Idaho Power/300, Brady/5-6.

[23] Idaho Power/300, Brady/5-9.

[24] Idaho Power/300, Brady/5.

$4.36 per Metric Million British Thermal Unit, which is $0.03 lower than the Henry Hub gas price used for the October Update.[25]

22. The March Forecast also included reduced PURPA generation relative to the October Update. The October Update included 337.2 average megawatts ("aMW") of available PURPA generation, whereas the PURPA generation included in the March Forecast was 335.2 aMW, a decrease of 2 aMW, or 0.6 percent.[26] Total PURPA expense included in the March Forecast is $251.5 million compared to $252.7 million included in the October Update, a decrease of $1.2 million, or 0.5 percent.[27] PURPA expense included in the 2025 March Forecast is $8.6 million more than PURPA expense included in the 2024 March Forecast.[28]

23. The Company also updated its forecast normalized load in the March Forecast. The forecast of system normalized load used for the March Forecast is 2,021 aMW compared to 2,028 aMW for the October Update, a decrease of 7 aMW.[29]

24. The Company also updated the hydro forecast.[30] The hydro generation forecasted for this year's March Forecast is 7.2 million MWh compared to 6.9 million MWh in last year's March Forecast, a 3 percent increase.[31]

25. Idaho Power proposed $17.6 million in system EIM benefits as an offset to NPSE in the 2025 March Forecast. On an Oregon-allocated basis, the EIM benefits totaled $0.7 million.[32]

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[25] Idaho Power/300, Brady/7.

[26] Idaho Power/300, Brady/9.

[27] Idaho Power/300, Brady/9.

[28] Idaho Power/300, Brady/9.

[29] Idaho Power/300, Brady/10.

[30] Idaho Power/300, Brady/10-11.

[31] Idaho Power/300, Brady/11.

[32] Idaho Power/300, Brady/16.

26. The 2025 March Forecast included forecast NPSE of $574.9 million, compared to the 2024 March Forecast NPSE of $588.4 million.[33] The 2024 March Forecast unit cost per MWh was $37.39 per MWh, compared to this year's March Forecast unit cost of $35.47 per MWh.[34] The overall revenue impact of the combined 2025 October Update and March Forecast is a decrease of $1.1 million, or 1.7 percent overall.[35] The $1.1 million decrease reflects an increase of $2.9 million in base rate revenues associated with the October Update and a $4.0 million decrease in Schedule 55 revenues associated with the March Forecast, as compared to what is currently included in Oregon customers' rates related to the 2024 APCU.[36]

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

28. Settlement conferences were held on January 8, 2025, February 12, 2025, and April 9, 2025. 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

29. The Stipulating Parties agree to the filed October Update and March Forecast amounts with adjustments related to EIM benefits and PURPA expenses. The Stipulating Parties also agree to the removal of the repricing methodology for modeled power market purchases and surplus sales and to additional reporting requirements regarding hedges, and filing requirements related to PURPA expenses. Finally, the Stipulating Parties agree to investigate potential modifications to the manner in which the Company models hedges in future APCU filings.

[33] Idaho Power/300, Brady/14.

[34] Idaho Power/300, Brady/17.

[35] Idaho Power/300, Brady/20.

[36] Idaho Power/300, Brady/20.

30. EIM Benefits: The Stipulating Parties agree to increase system-wide EIM benefits by $2.4 million compared to the filed 2025 March Forecast, resulting in an increase of $0.1 million in Oregon-allocated EIM benefits in the 2025 APCU. With the inclusion of this adjustment, the Stipulating Parties agree that the Company's forecasted EIM benefits for the 2025 APCU are reasonable. However, the Stipulating Parties do not necessarily agree on the methodology used to calculate this adjustment and every party reserves its rights to dispute the methodology used in this case in future proceedings.

31. PURPA Expenses: The Stipulating Parties agree to reduce system-wide PURPA expenses included in Idaho Power's 2025 APCU by $12.7 million compared to the filed 2025 March Forecast, resulting in a reduction to Oregon-allocated PURPA expenses of $0.5 million. With the inclusion of this adjustment, the Stipulating Parties agree that the Company's forecasted PURPA expenses for the 2025 APCU are reasonable. However, the Stipulating Parties do not necessarily agree on the methodology used to calculate this adjustment and every party reserves its rights to dispute the methodology used in this case in future proceedings.

32. Repricing: The Stipulating Parties agree to Idaho Power's proposed removal of the adjustment to reprice the AURORA-generated volumes of purchased power and surplus sales with an average forward electric price curve. The Stipulating Parties agree that the repricing adjustment should not be required in this docket or in future APCUs. As explained in the March Forecast, using the repricing adjustment for both the determination of base (October Update) and expected (March Forecast) NPSE would result in a combined increase of 3.01 percent, compared to the combined decrease of 1.69 percent using AURORA generated prices.[37]

33. PURPA Reporting: The Stipulating Parties agree that in future APCU filings, Parties will refer to the following definitions when requesting data related to PURPA

[37] Idaho Power/300, Brady/12-13.

expenses (1) October Update PURPA Expenses: forecast of normal repriced PURPA expenses for the upcoming test year; (2) March Forecast PURPA Expenses: forecast of expected repriced PURPA expenses for the upcoming test year; (3) Actual PURPA Expenses: PURPA expenses actually paid to projects based on their respective contract; and (4) Power Cost Adjustment Mechanism ("PCAM") PURPA Expenses: repriced PURPA expenses based on actual generation, as included in the PCAM. For purposes of analyzing the accuracy of the October Update PURPA Expenses or the March Forecast PURPA Expenses, Idaho Power recommends that Parties utilize the PCAM PURPA Expenses.

34. Hedge Reporting: The Stipulating Parties agree that beginning with the next APCU October Update, Idaho Power will file with the APCU October Update a report containing (1) all hedge transactions executed in accordance with the Energy Risk Management Standards ("ERMS") Risk Guidelines that settled reached maturation, or reached expiry during the prior APCU test year and their associated realized gain or loss value and (2) all outstanding hedge transactions executed in accordance with the ERMS Risk Guidelines, including their associated mark to market value, as of the prior month end.

35. Hedge Modeling in Future APCU Filings: The Stipulating parties will hold workshops to increase transparency into Idaho Power's hedging practices and examine if, and how, changes to hedging modeling can improve accuracy of hedging forecasts. The Stipulating Parties agree to begin these workshops no later than August 1, 2025. The Stipulating Parties will conclude these discussions by September 30, 2025, with any changes implemented as part of the 2026 APCU. Regardless of any changes, or lack thereof, Idaho Power will include a description of how Stipulating Parties met this condition as part of its 2026 October Update.

36. Based on the agreed-upon EIM benefit and PURPA expense adjustments, the Stipulating Parties agree to a revenue requirement decrease of $1.8 million or 2.62 percent overall. This revenue requirement is supported by the following exhibits to this stipulation:

Exhibit 1 shows the October Update NPSE based on the settlement terms, Exhibit 2 shows the March Forecast NPSE based on the settlement terms, Exhibit 3 shows the Combined Rate based on the settlement terms, and Exhibit 4 shows the rate spread based on the settlement terms.

37. 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.

38. The Stipulating Parties agree that rates agreed to by the terms of this Stipulation should be made effective on June 1, 2025, as permitted by the APCU mechanism.

39. 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.

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

41. 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.

42. 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.

43. 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.

44. 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.

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

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

STAFF

By: *<u>/s/ Natascha Smith</u>*

Date: <u>May 5, 2025</u>

IDAHO POWER

By: *<u>/s/ Adam Lowney</u>*

Date: <u>May 5, 2025</u>

OREGON CITIZENS' UTILITY BOARD

By: *<u>/s/ Claire Valentine-Fossum</u>*

Date: <u>May 5, 2025</u>

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 444

Exhibit 1 to Stipulation

October Update Net Power Supply Expense
Based on Settlement Terms

May 5, 2025

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR APRIL 1, 2025 -- MARCH 31, 2026 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2025 October Update
Variable Coal Handling Costs Modeled Using UE 301 & UE 314 Settlement Methodologies
AVERAGE

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	813,949.6	864,018.2	836,303.1	722,314.4	593,473.2	556,353.3	454,478.7	413,754.2	579,861.3	751,783.4	732,991.5	770,234.6	8,089,515.3
	Bridger													
2	Energy (MWh)	2,987.9	36,506.9	66,822.4	112,066.5	119,679.6	92,965.1	95,752.9	196,067.3	244,922.8	214,642.6	208,565.8	29,872.2	1,420,851.8
3	AURORA Modeled Expense ($ x 1000)	$ 136.1	$ 1,616.4	$ 2,734.5	$ 4,193.9	$ 4,436.0	$ 3,566.1	$ 3,675.1	$ 6,845.0	$ 8,419.5	$ 7,378.1	$ 7,126.5	$ 1,563.6	$ 51,690.6
4	AURORA Modeled Handling Expense ($ x 1000)	$ (1.8)	$ (21.5)	$ (39.4)	$ (66.1)	$ (70.6)	$ (54.8)	$ (56.5)	$ (115.7)	$ (144.5)	$ (126.6)	$ (123.1)	$ (17.6)	$ (838.3)
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 137.8	$ 1,637.9	$ 2,774.0	$ 4,260.0	$ 4,506.6	$ 3,620.9	$ 3,731.6	$ 6,960.6	$ 8,564.0	$ 7,504.7	$ 7,249.5	$ 1,581.2	$ 52,528.9
6	IPC Share of OHAG Expense ($ x 1000)	$ (201.1)	$ (201.1)	$ (201.1)	$ (201.1)	$ (201.1)	$ (201.1)	$ (201.1)	$ (201.1)	$ (201.1)	$ (201.1)	$ (201.1)	$ (201.1)	$ (2,413.8)
7	Total Expense ($ x 1000)	$ (63.3)	$ 1,436.8	$ 2,572.8	$ 4,058.9	$ 4,305.5	$ 3,419.8	$ 3,530.4	$ 6,759.5	$ 8,362.8	$ 7,303.6	$ 7,048.4	$ 1,380.0	$ 50,115.1
	Valmy													
8	Energy (MWh)	2,316.4	1,756.7	11,566.0	17,675.1	14,735.1	4,993.4	2,092.5	1,053.7	41,651.4	-	-	-	97,840.2
9	AURORA Modeled Expense ($ x 1000)	$ 136.3	$ 103.3	$ 669.8	$ 1,017.6	$ 847.6	$ 287.7	$ 121.9	$ 60.0	$ 2,365.5	$ -	$ -	$ -	$ 5,609.6
10	AURORA Modeled Handling Expense ($ x 1000)	$ 5.2	$ 4.0	$ 26.0	$ 39.8	$ 33.2	$ 11.2	$ 4.7	$ 2.4	$ 93.7	$ -	$ -	$ -	$ 220.1
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 131.1	$ 99.3	$ 643.8	$ 977.8	$ 814.4	$ 276.5	$ 117.2	$ 57.6	$ 2,271.8	$ -	$ -	$ -	$ 5,389.5
12	IPC Share of OHAG Expense ($ x 1000)	$ 351.7	$ 351.7	$ 351.7	$ 351.7	$ 351.7	$ 351.7	$ 351.7	$ 351.7	$ 351.7	$ -	$ -	$ -	$ 3,165.3
13	Usage Charges Paid to IPC ($ x 1000)	(2.7)	(2.7)	(2.7)	(2.7)	(2.7)	(2.7)	(2.7)	(2.7)	(2.7)	$ -	$ -	$ -	$ (24.146)
14	Total Expense ($ x 1000)	$ 480.1	$ 448.4	$ 992.8	$ 1,326.8	$ 1,163.5	$ 625.5	$ 466.2	$ 406.7	$ 2,620.8	$ -	$ -	$ -	$ 8,530.7
	Bridger Gas													
15	Energy (MWh)	62,960.4	64,054.7	79,192.0	75,874.3	78,030.9	63,262.9	76,002.6	48,958.5	21,798.9	23,214.9	59,031.9	86,276.2	738,658.1
16	Expense ($ x 1000)	$ 2,791.0	$ 2,582.4	$ 3,237.8	$ 4,082.7	$ 4,296.1	$ 3,496.0	$ 3,482.5	$ 3,723.4	$ 3,844.0	$ 4,017.8	$ 5,413.6	$ 4,763.0	$ 45,730.2
	Langley Gulch													
17	Energy (MWh)	189,767.8	189,502.7	210,651.6	221,230.3	209,978.5	204,300.9	224,062.2	45,644.0	330.8	1,911.0	78,832.3	166,201.2	1,742,413.1
18	Expense ($ x 1000)	$ 4,691.9	$ 4,028.4	$ 4,700.2	$ 6,641.4	$ 6,608.6	$ 6,209.0	$ 5,807.6	$ 2,223.4	$ 31.6	$ 179.6	$ 5,284.2	$ 6,398.9	$ 52,804.7
	Danskin													
19	Energy (MWh)	39,620.7	30,493.2	29,762.6	29,718.1	30,038.7	23,408.9	34,363.7	1,054.9	1,164.1	1,089.2	4,021.6	16,007.5	240,743.1
20	Expense ($ x 1000)	$ 1,365.1	$ 882.0	$ 975.8	$ 1,375.0	$ 1,424.6	$ 1,069.4	$ 1,291.1	$ 87.4	$ 168.8	$ 149.6	$ 458.0	$ 944.7	$ 10,191.3
	Bennett Mountain													
21	Energy (MWh)	23,236.0	19,594.0	19,384.5	21,036.4	19,987.3	16,856.3	21,408.6	1,416.1	2,302.1	1,352.3	5,917.1	15,260.9	167,751.8
22	Expense ($ x 1000)	$ 804.5	$ 564.8	$ 628.6	$ 970.7	$ 948.4	$ 768.2	$ 799.6	$ 116.9	$ 328.9	$ 184.3	$ 674.7	$ 901.2	$ 7,690.9
	Valmy 1 Gas													
23	Energy (MWh)	27,179.11	25,639.07	31,448.82	29,323.48	27,250.20	23,837.22	30,974.31	10,616.33	2,194.54	1,530.22	11,817.33	18,479.57	240,290.2
24	Expense ($ x 1000)	$ 1,095.2	$ 943.9	$ 1,233.7	$ 1,495.8	$ 1,431.2	$ 1,212.6	$ 1,326.1	$ 691.2	$ 250.2	$ 176.7	$ 1,082.9	$ 1,053.3	$ 11,992.9
25	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 2,892.7	$ 2,968.3	$ 2,892.7	$ 2,973.1	$ 2,977.8	$ 2,888.0	$ 2,977.8	$ 3,460.1	$ 3,559.4	$ 3,564.1	$ 3,247.3	$ 3,564.1	$ 37,965.5
	Purchased Power (Excluding PURPA)													
26	Market Energy (MWh)	36,255.2	58,941.4	110,637.7	344,506.1	328,213.6	164,092.9	114,216.5	324,206.9	344,442.8	281,540.8	107,560.9	90,579.0	2,305,193.9
27	Elkhorn Wind Energy (MWh)	26,081.1	23,901.8	22,170.1	29,029.0	23,542.1	19,209.0	22,048.2	26,774.7	29,962.1	34,666.4	26,098.3	26,035.7	309,518.3
28	Jackpot Solar Energy (MWh)	27,033.8	31,614.2	32,018.5	34,433.0	29,643.1	24,965.7	20,269.6	10,778.9	6,582.6	9,161.8	14,452.2	23,261.2	264,214.5
29	Neal Hot Springs Energy (MWh)	16,493.9	13,842.4	11,168.4	8,355.9	9,790.3	12,545.1	16,106.1	18,426.0	19,760.7	19,522.2	17,532.1	18,084.7	181,627.8
30	Raft River Geothermal Energy (MWh)	6,620.6	7,351.1	6,459.3	6,759.6	6,844.0	7,118.8	8,037.3	8,236.3	8,785.8	8,805.9	8,076.8	8,442.3	91,537.7
31	Black Mesa Solar Energy (MWh)	8,908.6	10,418.0	10,551.3	11,346.9	9,768.5	8,227.1	6,679.6	3,552.0	2,169.2	3,019.2	4,762.5	7,665.4	87,068.3
32	Franklin Solar Energy (MWh)	11,245.1	15,587.8	19,289.5	24,015.6	26,418.2	30,080.3	30,464.0	26,217.9	23,827.4	18,636.5	9,889.3	10,024.7	245,696.4
33	Pleasant Valley Solar Energy (MWh)	15,780.5	25,862.8	37,881.9	50,876.1	56,077.0	62,201.1	63,832.8	54,669.4	46,815.6	33,144.6	15,752.6	14,107.5	477,002.0
34	Total Energy Excl. PURPA (MWh)	148,418.8	187,519.4	250,176.6	509,322.2	490,296.8	328,440.0	281,654.2	472,862.0	482,346.3	408,497.4	204,124.7	198,200.5	3,961,858.7
35	Market Expense ($ x 1000)	$ 858.5	$ 1,151.0	$ 3,333.4	$ 12,764.9	$ 12,507.8	$ 5,850.9	$ 3,685.1	$ 14,097.8	$ 19,892.9	$ 14,926.1	$ 5,447.4	$ 3,083.5	$ 97,599.3
36	Elkhorn Wind Expense ($ x 1000)	$ 2,028.3	$ 1,858.8	$ 1,724.2	$ 2,257.6	$ 1,830.9	$ 1,493.9	$ 1,714.7	$ 2,082.3	$ 2,330.2	$ 2,696.0	$ 2,029.7	$ 2,024.8	$ 24,071.2
37	Jackpot Solar Expense ($ x 1000)	$ 607.7	$ 710.7	$ 719.8	$ 774.1	$ 666.4	$ 561.2	$ 455.7	$ 242.3	$ 148.0	$ 206.0	$ 324.9	$ 522.9	$ 5,939.6
38	Neal Hot Springs Expense ($ x 1000)	$ 2,099.3	$ 1,761.9	$ 1,421.5	$ 1,063.5	$ 1,246.1	$ 1,596.7	$ 2,050.0	$ 2,345.3	$ 2,515.1	$ 2,484.8	$ 2,231.5	$ 2,301.8	$ 23,117.6
39	Raft River Geothermal Expense ($ x 1000)	$ 471.0	$ 523.0	$ 459.5	$ 480.9	$ 486.9	$ 506.4	$ 571.8	$ 585.9	$ 625.0	$ 626.5	$ 574.6	$ 600.6	$ 6,512.0
40	Black Mesa Solar Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	Franklin Solar Expense ($ x 1000)	$ 335.6	$ 465.1	$ 575.6	$ 716.6	$ 788.3	$ 897.6	$ 909.1	$ 782.3	$ 711.0	$ 556.1	$ 295.1	$ 299.1	$ 7,331.6
42	Pleasant Valley Solar Expense ($ x 1000)	$ 114.2	$ 240.6	$ 2,086.9	$ 3,989.4	$ 2,780.0	$ 1,618.2	$ 1,504.7	$ 1,703.9	$ 1,937.7	$ 1,039.4	$ 721.8	$ 81.0	$ 17,817.8
43	Total Expense Excl. PURPA ($ x 1000)	$ 6,514.7	$ 6,711.1	$ 10,320.9	$ 22,046.9	$ 20,306.3	$ 12,525.0	$ 10,891.0	$ 21,839.9	$ 28,160.0	$ 22,534.8	$ 11,624.9	$ 8,913.8	$ 182,389.0
	Storage													
44	Black Mesa Battery Energy (MWh)	(706.6)	(759.8)	(541.7)	(671.9)	(682.5)	(509.4)	(537.1)	(368.9)	(238.5)	(275.7)	(474.2)	(689.0)	(6,455.33)
45	80 MW Hemingway Battery Energy (MWh)	(2,261.8)	(2,254.8)	(1,713.7)	(1,753.8)	(1,754.8)	(1,833.8)	(2,479.9)	(2,373.8)	(2,439.8)	(2,781.2)	(2,529.1)	(2,588.8)	(26,765.17)
46	11 MW Grid Battery Energy (MWh)	(235.7)	(237.3)	(188.8)	(216.5)	(226.9)	(182.0)	(191.4)	(169.1)	(171.2)	(189.0)	(226.3)	(241.5)	(2,475.76)
47	Franklin Battery Energy (MWh)	(998.2)	(1,147.5)	(826.9)	(1,132.1)	(1,160.4)	(855.9)	(888.5)	(807.6)	(827.6)	(788.3)	(804.4)	(982.1)	(11,219.48)
48	36 MW Hemingway Battery Energy (MWh)	(822.6)	(827.0)	(663.5)	(759.6)	(777.5)	(718.4)	(796.5)	(741.9)	(795.0)	(783.5)	(862.1)	(901.3)	(9,448.76)
49	Happy Valley Battery Energy (MWh)	(1,789.5)	(1,800.3)	(1,492.4)	(1,639.7)	(1,668.9)	(1,568.5)	(1,759.7)	(1,666.0)	(1,802.1)	(1,797.9)	(1,916.9)	(1,995.3)	(20,897.07)
50	Kuna Battery Energy (MWh)	(3,582.0)	(3,566.0)	(3,001.2)	(3,214.6)	(3,266.0)	(3,090.2)	(3,587.1)	(3,347.1)	(3,688.4)	(3,656.4)	(3,820.2)	(3,978.1)	(41,797.22)
51	Total Storage (MWh)	(10,396.4)	(10,592.6)	(8,428.1)	(9,388.2)	(9,536.9)	(8,758.2)	(10,240.2)	(9,474.4)	(9,962.5)	(10,271.9)	(10,633.2)	(11,376.2)	(119,058.8)

52	Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Demand Response													
53	Energy (MWh)	-	-	3,779.5	12,991.3	388.4	-	-	-	-	-	-	-	17,159.2
54	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Oregon Solar													
55	Energy (MWh)	73.1	88.6	102.2	98.2	88.9	75.2	68.7	47.6	24.8	36.2	33.5	74.9	811.9
56	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Surplus Sales													
57	Energy (MWh)	370,020.6	328,360.2	232,270.4	53,236.9	64,877.0	132,460.4	170,220.1	13,623.5	17,268.7	54,284.3	159,543.5	189,419.7	1,785,585.2
58	Revenue ($ x 1000)	$ 12,610.1	$ 10,383.3	$ 9,353.8	$ 2,955.1	$ 3,743.0	$ 6,906.5	$ 7,956.0	$ 773.9	$ 1,144.5	$ 2,835.4	$ 9,695.4	$ 8,071.5	$ 76,428.6
59	Surplus Sales - Third Party Transmission Losses ($ x 1000)	$ 752.8	$ 672.7	$ 864.2	$ 1,101.5	$ 1,136.1	$ 1,009.0	$ 983.2	$ 1,208.0	$ 1,603.1	$ 1,425.3	$ 1,322.4	$ 992.7	$ 13,071.11
60	Lamb Weston Surplus Sales ($ x 1000)	$ 218.43	$ 216.04	$ 330.86	$ 283.99	$ 233.31	$ 245.77	$ 278.63	$ 223.76	$ 244.73	$ 356.58	$ 307.08	$ 349.19	$ 3,288.4
61	Net Power Supply Expenses ($ x 1000)	$ 6,990.5	$ 9,293.9	$ 17,006.5	$ 40,630.7	$ 38,349.5	$ 24,052.0	$ 21,354.4	$ 37,102.7	$ 44,334.1	$ 33,493.2	$ 23,509.0	$ 18,505.6	**$ 314,622.2**
	PURPA													
62	Energy (MWh)	287,733.2	310,339.7	302,418.3	279,831.6	279,844.4	234,189.4	229,942.3	169,293.6	183,869.9	195,701.9	232,427.2	248,420.4	2,954,011.8
63	Cost($ X 1000)	$ 19,674.9	$ 22,491.0	$ 26,110.8	$ 28,598.0	$ 28,496.3	$ 20,684.8	$ 18,791.9	$ 16,843.8	$ 18,367.1	$ 16,676.6	$ 19,448.5	$ 16,508.3	$ 239,991.8
64	EIM Benefits ($ x 1000)													$ 20,026.2
65	Total Net Power Supply Expenses ($ x 1000)	$ 26,665.40	$ 31,784.85	$ 43,117.36	$ 69,228.73	$ 66,845.78	$ 44,736.79	$ 40,146.29	$ 53,946.50	$ 62,701.25	$ 50,169.78	$ 42,957.48	$ 35,013.83	**$ 534,587.8**
66	Sales at Customer Level (In 000s MWH)	1,136.87	1,185.07	1,339.03	1,649.96	1,772.30	1,565.40	1,207.07	1,143.36	1,311.06	1,380.56	1,336.16	1,281.85	16,308.683
67	Lamb Weston kWh Sales (In 000s MWH)	0.77	1.02	2.18	1.87	1.11	0.86	1.32	0.79	1.13	2.35	2.02	2.30	17.712
68	Sales at Customer Level - Net Black Mesa, LW (In 000s MWH)	1,127.51	1,173.99	1,326.67	1,637.13	1,761.77	1,556.59	1,199.30	1,139.14	1,307.83	1,375.30	1,329.54	1,272.16	16,206.928
69	Hours in Month	720	744	720	744	744	720	744	721	744	744	672	743	8760
70	Unit Cost / MWH (for PCAM)	$ 23.65	$ 27.07	$ 32.50	$ 42.29	$ 37.94	$ 28.74	$ 33.47	$ 47.36	$ 47.94	$ 36.48	$ 32.31	$ 27.52	**$ 32.99**

PURPA Stip Decrease	
$	12,700.00

EIM Stip Increase	
$	2,400.00

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 444

Exhibit 2 to Stipulation

March Forecast Net Power Supply Expense
Based on Settlement Terms

May 5, 2025

IDAHO POWER COMPANY EXPECTED POWER SUPPLY EXPENSE FOR APRIL 1, 2025 -- MARCH 31, 2026 (One Hydro Condition)
2025 APCU March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	947,873.9	986,768.7	860,219.6	605,787.6	499,016.5	477,297.3	422,270.6	364,572.3	435,356.9	483,378.4	499,225.3	589,944.4	7,171,711.4
	Bridger													
2	Energy (MWh)	6,603.7	22,641.5	28,220.9	101,660.7	104,795.1	79,066.2	81,885.1	112,146.6	227,859.9	235,186.8	188,603.4	29,291.4	1,217,961.3
3	AURORA Modeled Expense ($ x 1000)	$ 358.5	$ 1,190.8	$ 1,527.3	$ 3,899.8	$ 4,000.2	$ 3,155.5	$ 3,266.5	$ 4,214.8	$ 7,941.2	$ 7,893.3	$ 6,393.2	$ 1,528.6	$ 45,369.7
4	AURORA Modeled Handling Expense ($ x 1000)	$ (6.1)	$ (20.8)	$ (26.0)	$ (93.5)	$ (96.4)	$ (72.7)	$ (75.3)	$ (103.2)	$ (209.6)	$ (216.4)	$ (173.5)	$ (26.9)	$ (1,120.5)
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 364.6	$ 1,211.6	$ 1,553.2	$ 3,993.3	$ 4,096.6	$ 3,228.3	$ 3,341.8	$ 4,318.0	$ 8,150.9	$ 8,109.7	$ 6,566.7	$ 1,555.6	$ 46,490.3
6	IPC Share of OHAG Expense ($ x 1000)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (1,054.6)
7	Total Expense ($ x 1000)	$ 276.7	$ 1,123.7	$ 1,465.3	$ 3,905.4	$ 4,008.7	$ 3,140.4	$ 3,254.0	$ 4,230.1	$ 8,063.0	$ 8,021.8	$ 6,478.8	$ 1,467.7	$ 45,435.6
	Valmy													
8	Energy (MWh)	2,528.7	4,741.3	10,878.5	27,914.6	27,153.9	22,752.7	8,849.2	13,692.3	45,576.3	-	-	-	164,087.5
9	AURORA Modeled Expense ($ x 1000)	$ 147.3	$ 276.1	$ 633.4	$ 1,625.0	$ 1,580.7	$ 1,324.8	$ 515.3	$ 797.2	$ 2,651.9	$ -	$ -	$ -	$ 9,551.7
10	AURORA Modeled Handling Expense ($ x 1000)	$ 5.7	$ 10.7	$ 24.5	$ 62.8	$ 61.1	$ 51.2	$ 19.9	$ 30.8	$ 102.5	$ -	$ -	$ -	$ 369.2
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 141.6	$ 265.5	$ 608.9	$ 1,562.2	$ 1,519.6	$ 1,273.6	$ 495.4	$ 766.4	$ 2,549.3	$ -	$ -	$ -	$ 9,182.5
12	IPC Share of OHAG Expense ($ x 1000)	$ 416.8	$ 416.8	$ 416.8	$ 416.8	$ 416.8	$ 416.8	$ 416.8	$ 416.8	$ 416.8	$ -	$ -	$ -	$ 3,751.3
13	Usage Charges Paid to IPC ($ x 1000)	$ (21.6)	$ (21.6)	$ (21.6)	$ (21.6)	$ (21.6)	$ (21.6)	$ (21.6)	$ (21.6)	$ (21.6)	$ -	$ -	$ -	$ (194.442)
14	Total Expense ($ x 1000)	$ 536.8	$ 660.7	$ 1,004.1	$ 1,957.4	$ 1,914.8	$ 1,668.8	$ 890.6	$ 1,161.6	$ 2,944.5	$ -	$ -	$ -	$ 12,739.3
	Bridger Gas													
15	Energy (MWh)	55,324.9	48,358.1	65,753.9	84,364.6	87,239.7	68,330.1	64,780.1	72,371.8	71,125.9	45,425.7	75,860.4	60,088.9	799,024.1
16	Expense ($ x 1000)	$ 2,494.6	$ 2,225.5	$ 2,832.3	$ 3,807.6	$ 3,959.3	$ 3,238.1	$ 3,033.4	$ 3,923.0	$ 4,980.0	$ 3,795.4	$ 4,669.9	$ 2,821.9	$ 41,781.0
	Langley Gulch													
17	Energy (MWh)	129,673.4	83,411.1	205,012.4	212,408.5	207,047.3	200,678.7	216,383.6	116,935.6	-	10,343.6	200,740.9	221,990.8	1,804,625.9
18	Expense ($ x 1000)	$ 3,087.9	$ 1,944.2	$ 3,989.7	$ 5,170.1	$ 5,556.1	$ 5,002.2	$ 5,165.0	$ 4,419.5	$ -	$ 751.5	$ 8,389.0	$ 5,611.6	$ 49,086.8
	Danskin													
19	Energy (MWh)	26,951.8	29,893.9	57,740.7	47,654.0	44,502.9	18,212.4	12,015.1	14,077.7	13,388.1	30,348.4	30,021.4	28,702.2	353,508.5
20	Expense ($ x 1000)	$ 794.5	$ 738.3	$ 1,497.6	$ 1,697.1	$ 1,723.9	$ 706.8	$ 442.2	$ 707.8	$ 1,082.5	$ 2,442.5	$ 2,035.5	$ 1,075.3	$ 14,943.8
	Bennett Mountain													
21	Energy (MWh)	23,045.2	21,678.3	56,406.7	33,607.5	31,708.8	6,835.2	758.7	916.7	948.4	20,667.6	19,449.0	18,679.7	234,701.6
22	Expense ($ x 1000)	$ 663.4	$ 530.7	$ 1,434.2	$ 1,166.2	$ 1,194.9	$ 276.6	$ 30.7	$ 50.2	$ 81.1	$ 1,675.0	$ 1,304.2	$ 696.9	$ 9,103.9
	Valmy 1 Gas													
23	Energy (MWh)	-	-	-	-	-	-	-	-	-	26,882.01	30,264.27	20,454.40	77,600.7
24	Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,802.9	$ 1,762.8	$ 843.9	$ 4,409.6
25	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,486.0	$ 1,524.2	$ 1,486.0	$ 1,524.2	$ 1,524.2	$ 1,486.0	$ 1,524.2	$ 2,053.3	$ 2,110.5	$ 3,682.2	$ 3,358.5	$ 3,682.2	$ 25,441.7
	Purchased Power (Excluding PURPA)													
26	Market Energy (MWh)	773.9	4,081.7	55,627.8	422,438.3	396,810.4	244,576.1	210,609.7	364,266.2	452,441.5	389,113.3	123,912.0	105,969.1	2,770,620.0
27	Elkhorn Wind Energy (MWh)	26,165.0	24,136.8	21,786.6	28,379.7	21,797.4	20,459.4	21,216.7	26,963.5	32,275.6	34,175.7	26,019.7	26,142.3	309,518.4
28	Jackpot Solar Energy (MWh)	26,363.5	30,146.4	31,681.1	37,116.7	31,174.6	25,406.3	19,924.3	10,703.4	6,807.1	8,837.3	14,547.6	21,508.4	264,216.6
29	Neal Hot Springs Energy (MWh)	16,493.9	13,842.4	11,168.4	8,355.9	9,790.3	12,545.1	16,106.1	18,426.0	19,760.7	19,522.2	17,532.1	18,085.3	181,628.5
30	Raft River Geothermal Energy (MWh)	6,620.6	7,351.1	6,459.3	6,759.6	6,844.0	7,118.8	8,037.3	8,236.3	8,785.8	8,805.9	8,076.8	8,442.6	91,538.0
31	Black Mesa Solar Energy (MWh)	8,687.73	9,934.3	10,440.1	12,231.3	10,273.2	8,372.3	6,565.8	3,527.2	2,243.2	2,912.2	4,794.0	7,087.8	87,069.0
32	Franklin Solar Energy (MWh)	22,071.9	26,723.0	29,693.7	30,621.4	27,423.3	23,872.6	18,296.4	11,125.6	10,026.2	11,922.8	14,116.4	19,804.7	245,697.9
33	Pleasant Valley Solar Energy (MWh)	49,042.7	56,728.0	61,962.0	64,718.3	56,590.3	45,337.9	32,825.4	18,087.1	14,107.6	16,114.9	23,502.1	37,985.8	477,002.0
34	Total Energy Excl. PURPA (MWh)	156,219.1	172,943.7	228,818.9	610,621.2	560,703.5	387,688.5	333,581.8	461,335.2	546,447.7	491,404.3	232,500.6	245,026.0	4,427,290.4
35	Market Expense ($ x 1000)	$ 20.0	$ 82.5	$ 1,702.6	$ 16,002.5	$ 15,328.0	$ 8,403.8	$ 6,970.9	$ 14,406.5	$ 22,935.9	$ 18,301.4	$ 5,409.4	$ 2,649.2	$ 112,212.7
36	Elkhorn Wind Expense ($ x 1000)	$ 2,034.9	$ 1,877.1	$ 1,694.3	$ 2,207.1	$ 1,695.2	$ 1,591.1	$ 1,650.0	$ 2,097.0	$ 2,510.1	$ 2,657.8	$ 2,023.6	$ 2,033.1	$ 24,071.2
37	Jackpot Solar Expense ($ x 1000)	$ 592.7	$ 677.7	$ 712.2	$ 834.4	$ 700.8	$ 571.1	$ 447.9	$ 240.6	$ 153.0	$ 198.7	$ 327.0	$ 483.5	$ 5,939.6
38	Neal Hot Springs Expense ($ x 1000)	$ 2,099.3	$ 1,761.9	$ 1,421.5	$ 1,063.5	$ 1,246.1	$ 1,596.7	$ 2,050.0	$ 2,345.3	$ 2,515.1	$ 2,484.8	$ 2,231.5	$ 2,301.9	$ 23,117.7
39	Raft River Geothermal Expense ($ x 1000)	$ 471.0	$ 523.0	$ 459.5	$ 480.9	$ 486.9	$ 506.4	$ 571.8	$ 585.9	$ 625.0	$ 626.5	$ 574.6	$ 600.6	$ 6,512.0
40	Black Mesa Solar Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	Franklin Solar Expense ($ x 1000)	$ 658.6	$ 797.4	$ 886.1	$ 913.7	$ 818.3	$ 712.4	$ 546.0	$ 332.0	$ 299.2	$ 355.8	$ 421.2	$ 591.0	$ 7,331.6
42	Pleasant Valley Solar Expense ($ x 1000)	$ 114.2	$ 240.6	$ 2,086.9	$ 3,989.4	$ 2,780.0	$ 1,618.2	$ 1,504.7	$ 1,703.9	$ 1,937.7	$ 1,039.4	$ 721.8	$ 81.0	$ 17,817.8
43	Total Expense Excl. PURPA ($ x 1000)	$ 5,990.7	$ 5,960.1	$ 8,963.1	$ 25,491.5	$ 23,055.3	$ 14,999.7	$ 13,741.3	$ 21,711.2	$ 30,976.0	$ 25,664.3	$ 11,709.0	$ 8,740.3	$ 197,002.6
	Storage													
44	Black Mesa Battery Energy (MWh)	(631.4)	(507.9)	(555.4)	(616.7)	(610.6)	(533.8)	(502.7)	(374.1)	(226.1)	(312.1)	(494.9)	(651.2)	(6,016.99)
45	80 MW Hemingway Battery Energy (MWh)	(2,547.8)	(2,203.8)	(1,787.3)	(1,750.6)	(1,764.9)	(1,860.9)	(2,769.1)	(2,360.1)	(2,339.6)	(2,777.3)	(2,538.0)	(2,579.2)	(27,278.59)
46	11 MW Grid Battery Energy (MWh)	(241.2)	(232.8)	(210.0)	(219.9)	(227.7)	(219.6)	(236.4)	(248.2)	(222.6)	(241.3)	(233.2)	(232.8)	(2,765.59)
47	Franklin Battery Energy (MWh)	(1,087.5)	(953.4)	(902.8)	(1,124.5)	(1,159.6)	(949.8)	(910.0)	(724.9)	(705.8)	(745.9)	(839.3)	(1,115.2)	(11,218.57)
48	36 MW Hemingway Battery Energy (MWh)	(809.2)	(797.6)	(666.5)	(770.4)	(794.7)	(758.4)	(830.0)	(892.5)	(813.9)	(905.7)	(882.1)	(904.6)	(9,825.61)
49	Happy Valley Battery Energy (MWh)	-	-	(1,479.0)	(1,657.9)	(1,686.3)	(1,604.2)	(1,793.8)	(1,882.6)	(1,717.1)	(1,998.7)	(1,885.8)	(1,846.6)	(17,551.93)
50	Kuna Battery Energy (MWh)	-	-	(2,854.3)	(3,242.6)	(3,287.9)	(3,188.8)	(3,781.6)	(3,812.0)	(3,467.1)	(3,871.5)	(3,732.1)	(3,910.8)	(35,148.73)
51	Total Storage (MWh)	(5,317.1)	(4,695.5)	(8,455.3)	(9,382.6)	(9,531.6)	(9,115.5)	(10,823.5)	(10,294.4)	(9,492.3)	(10,852.4)	(10,605.4)	(11,240.4)	(109,806.0)
52	Kuna Battery Lease Expense ($ x 1000)	$ -	$ -	$ 1,795.50	$ 1,795.50	$ 1,795.50	$ 1,795.50	$ 1,795.50	$ 1,795.50	$ 1,795.50	$ 1,795.50	$ 1,795.50	$ 1,795.50	$ 17,955.00

	Net Hedges													
53	Energy (MWh)	-	-	6,400.0	23,400.0	24,600.0	-	-	24,000.0	-	-	-	-	78,400.0
54	Cost($ X 1000)	$ -	$ -	$ 288.00	$ 1,737.45	$ 1,820.40	$ -	$ -	$ 1,896.00	$ -	$ -	$ -	$ -	$ 5,741.85
	Demand Response													
55	Energy (MWh)	-	-	3,779.5	12,991.3	388.4	-	-	-	-	-	-	-	17,159.2
56	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Oregon Solar													
57	Energy (MWh)	73.1	88.6	102.2	98.2	88.9	75.2	68.7	47.6	24.8	36.2	33.5	74.9	811.9
58	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Surplus Sales													
59	Energy (MWh)	414,882.7	303,606.7	192,319.7	42,656.5	41,669.3	76,243.2	81,369.8	28,016.1	7,860.7	10,749.0	136,849.5	129,280.8	1,465,503.9
60	Revenue ($ x 1000)	$ 14,354.3	$ 9,584.6	$ 7,524.3	$ 2,345.7	$ 2,472.7	$ 4,052.9	$ 4,086.4	$ 1,596.6	$ 529.8	$ 710.0	$ 8,846.3	$ 5,470.3	$ 61,573.8
61	Surplus Sales - Third Party Transmission Losses ($ x 1000)	$ 768.5	$ 685.1	$ 852.7	$ 1,121.7	$ 1,155.5	$ 1,004.2	$ 1,010.1	$ 1,141.1	$ 1,452.0	$ 1,359.3	$ 1,263.1	$ 850.6	$ 12,663.85
62	Lamb Weston Surplus Sales ($ x 1000)	$ 359.56	$ 480.09	$ 1,021.17	$ 876.51	$ 518.48	$ 404.55	$ 619.17	$ 368.33	$ 531.03	$ 1,100.56	$ 947.79	$ 1,077.75	$ 8,305.0
63	Net Power Supply Expenses ($ x 1000)	$ (151.7)	$ 3,957.5	$ 15,357.6	$ 43,908.7	$ 42,406.6	$ 26,852.4	$ 24,161.1	$ 38,842.3	$ 49,520.3	$ 46,461.3	$ 30,445.9	$ 19,336.5	$ 341,098.5
	PURPA													
64	Energy (MWh)	292,249.3	313,878.1	296,835.5	278,095.0	271,020.5	227,790.4	217,033.4	174,393.5	187,690.9	197,773.5	232,736.2	246,596.3	2,936,092.6
65	Cost($ X 1000)	$ 19,494.9	$ 22,389.3	$ 26,032.8	$ 28,545.3	$ 28,450.0	$ 20,274.1	$ 18,098.2	$ 16,712.0	$ 18,350.2	$ 16,680.9	$ 19,952.7	$ 16,480.0	$ 238,760.4
66	EIM Benefits ($ x 1000)													$ 20,026.2
67	Total Net Power Supply Expenses ($ x 1000)	$ 19,343.13	$ 26,346.84	$ 41,390.42	$ 72,453.99	$ 70,856.59	$ 47,126.49	$ 42,259.29	$ 55,554.25	$ 67,870.49	$ 63,142.21	$ 50,398.67	$ 35,816.59	$ 559,832.7
68	Sales at Customer Level (In 000s MWH)	1,136.87	1,185.07	1,339.03	1,649.96	1,772.30	1,565.40	1,207.07	1,143.36	1,311.06	1,380.56	1,336.16	1,281.853	16,308.683
69	Lamb Weston kWh Sales (In 000s MWH)	0.77	1.02	2.18	1.87	1.11	0.86	1.32	0.79	1.13	2.35	2.02	2.298	17.712
70	Sales at Customer Level - Net Black Mesa, LW (In 000s MWH)	1,127.72	1,174.46	1,326.78	1,636.28	1,761.28	1,556.45	1,199.41	1,139.17	1,307.76	1,375.40	1,329.51	1,272.71	16,206.927
71	Hours in Month	720	744	720	744	744	720	744	721	744	744	672	743	8760
72	Unit Cost / MWH (for PCAM)	$ 17.15	$ 22.43	$ 31.20	$ 44.28	$ 40.23	$ 30.28	$ 35.23	$ 48.77	$ 51.90	$ 45.91	$ 37.91	$ 28.14	$ 34.54

PURPA Stip Decrease
$ 12,700.00

EIM Stip Increase
$ 2,400.00

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 444

Exhibit 3 to Stipulation

Combined Rate
Based on Settlement Terms

May 5, 2025

Idaho Power Company
2025 APCU Combined Rate Calculation
April 2025 - March 2026

Line		
	OCTOBER UPDATE	
1	Forecast of Normalized Sales (MWh)	16,206,928
2	Total Net Power Supply Expense	$534,587,808
3	October APCU Unit Cost ($/MWh)	$32.99
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	16,206,927
5	Total Net Power Supply Expense	$559,832,734
6	March Forecast Unit Cost ($/MWh)	$34.54
7	Sales Adjusted Forecast Power Cost Change	$25,120,738
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$23,864,701
10	**March Forecast Rate ($/MWh)**	$1.47
11	**Combined Rate ($/MWh)**	$34.46

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 444

Exhibit 4 to Stipulation

Rate Spread
Based on Settlement Terms

May 5, 2025

Idaho Power Company
Stipulated Revenue Spread
2025 APCU October Update

Line No.		
1	2025 October Update Oregon Jurisdictional Share of Base NPSE = $32.99/MWh x 674,329.427 MWhs =	$ 22,246,128
2	**Oregon Allocated EIM Costs***	$0
3	**Proposed October Update APCU Revenue Requirement**	**$ 22,246,128**

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	RESIDENTIAL TOD PILOT (5)	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 2025 - March 2026 Generation Level Normalized Sales (kWh)**	**715,527,762**	206,320,058	129,240	21,399,841	118,144,838	23,885,954	3,435,040	140,323	164,279,956	102,927,893	74,474,590	5,787	354,152	30,090
5	**Class Share of April 2025 - March 2026 Generation Level Normalized Sales (kWh)**	**100%**	28.83%	0.02%	2.99%	16.51%	3.34%	0.48%	0.02%	22.96%	14.38%	10.41%	0.00%	0.05%	0.00%
6	**2025 October Update Class Allocated Base NPSE**	**$ 22,246,128**	$ 6,414,597	$ 4,018	$ 665,332	$ 3,673,184	$ 742,627	$ 106,797	$ 4,363	$ 5,107,549	$ 3,200,081	$ 2,315,453	$ 180	$ 11,011	$ 936
7	**June 2025 - May 2026 Loss-Adjusted Normalized Sales (kWh)**	**674,494,965**	192,172,586	120,915	19,929,935	110,029,532	22,731,418	3,338,231	130,655	156,308,236	100,027,107	69,343,194	5,388	329,751	28,017
8	**Proposed APCU Rates for 2025 October Update ($/kWh)**	**0.032982**	0.033379	0.033231	0.033384	0.033384	0.032670	0.031992	0.033391	0.032676	0.031992	0.033391	0.033391	0.033391	0.033391
9	**Proposed October Update APCU Revenue Requirement**	**$ 22,246,128**	$ 6,414,597	$ 4,018	$ 665,332	$ 3,673,184	$ 742,627	$ 106,797	$ 4,363	$ 5,107,549	$ 3,200,081	$ 2,315,453	$ 180	$ 11,011	$ 936

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	RESIDENTIAL TOD PILOT (5)	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	**APCU Rates for 2024 October Update ($/kWh) - Order No. 24-151**	**0.029627**	0.029971	0.029996	0.029981	0.029980	0.029341	0.028730	0.029987	0.029341	0.028730	0.029987	0.029987	0.029987	0.029987
11	**June 2025 - May 2026 Loss-Adjusted Normalized Sales (kWh)**	**674,494,965**	192,172,586	120,915	19,929,935	110,029,532	22,731,418	3,338,231	130,655	156,308,236	100,027,107	69,343,194	5,388	329,751	28,017
12	**Base NPSE Recovered under Current APCU Rates**	**$ 19,976,489**	$ 5,759,572	$ 3,627	$ 597,511	$ 3,298,739	$ 666,967	$ 95,908	$ 3,918	$ 4,586,187	$ 2,873,801	$ 2,079,370	$ 162	$ 9,888	$ 840

Idaho Power Company
Stipulated Revenue Spread
2025 APCU March Forecast

Line No.		
1	Oregon Jurisdictional Share of 2024 March Forecast NPSE = $1.47/MWh x 674,329.427 MWhs =	$ 991,264

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	RESIDENTIAL TOD PILOT (5)	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 2025 - March 2026 Generation Level Normalized Sales (kWh)	715,527,762	206,320,058	129,240	21,399,841	118,144,838	23,885,954	3,435,040	140,323	164,279,956	102,927,893	74,474,590	5,787	354,152	30,090
3	Class Share of April 2025 - March 2026 Generation Level Normalized Sales (kWh)	100%	28.83%	0.02%	2.99%	16.51%	3.34%	0.48%	0.02%	22.96%	14.38%	10.41%	0.00%	0.05%	0.00%
4	2025 March Forecast Class Allocated NPSE	$ 991,264	$ 285,828	$ 179	$ 29,647	$ 163,673	$ 33,091	$ 4,759	$ 194	$ 227,587	$ 142,592	$ 103,174	$ 8	$ 491	$ 42
5	June 2025 - May 2026 Loss-Adjusted Normalized Sales (kWh)	674,494,965	192,172,586	120,915	19,929,935	110,029,532	22,731,418	3,338,231	130,655	156,308,236	100,027,107	69,343,194	5,388	329,751	28,017
6	Proposed APCU Rates for 2025 March Forecast ($/kWh)	0.001470	0.001487	0.001481	0.001488	0.001488	0.001456	0.001426	0.001488	0.001456	0.001426	0.001488	0.001488	0.001488	0.001488
7	Proposed March Forecast Revenue Requirement	$ 991,264	$ 285,828	$ 179	$ 29,647	$ 163,673	$ 33,091	$ 4,759	$ 194	$ 227,587	$ 142,592	$ 103,174	$ 8	$ 491	$ 42

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	RESIDENTIAL TOD PILOT (5)	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	Current APCU Rates for 2024 March Forecast ($/kWh) - Order No. 24-151	0.007457	0.007544	0.007550	0.007546	0.007546	0.007385	0.007232	0.007548	0.007385	0.007232	0.007548	0.007548	0.007548	0.007548
9	June 2025 - May 2026 Loss-Adjusted Normalized Sales (kWh)	674,494,965	192,172,586	120,915	19,929,935	110,029,532	22,731,418	3,338,231	130,655	156,308,236	100,027,107	69,343,194	5,388	329,751	28,017
10	NPSE Recovered under Current March Forecast Rates	$ 5,028,164	$ 1,449,708	$ 913	$ 150,396	$ 830,306	$ 167,878	$ 24,140	$ 986	$ 1,154,362	$ 723,347	$ 523,386	$ 41	$ 2,489	$ 211

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2025

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers (1)	Normalized Energy (kWh) (1)	Current Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	2025 October Update Proposed Base NPSE Revenue	Total Proposed Base Revenue	2025 October Update Proposed Adjustments to Base Revenue	2025 October Update Base Revenue Percent Change
	Uniform Tariff Rates:										
1	Residential Service	1	14,183	192,172,586	$ 15,776,853	$ 5,759,572	$ 21,536,425	$ 6,414,597	$ 22,191,450	$ 655,026	3.04%
2	Residential Service - Time-of-Day Pilot	5	5	120,915	$ 9,116	$ 3,627	$ 12,743	$ 4,018	$ 13,134	$ 391	3.07%
3	Small General Service	7	2,778	19,929,935	$ 1,903,053	$ 597,511	$ 2,500,563	$ 665,332	$ 2,568,385	$ 67,822	2.71%
4	Large General Secondary	9S	880	110,029,532	$ 6,331,182	$ 3,298,739	$ 9,629,921	$ 3,673,184	$ 10,004,366	$ 374,445	3.89%
5	Large General Primary	9P	8	22,731,418	$ 1,128,830	$ 666,967	$ 1,795,796	$ 742,627	$ 1,871,456	$ 75,660	4.21%
6	Large General Transmission	9T	1	3,338,231	$ 136,520	$ 95,908	$ 232,428	$ 106,797	$ 243,317	$ 10,889	4.68%
7	Dusk to Dawn Lighting	15	0	130,655	$ 114,534	$ 3,918	$ 118,452	$ 4,363	$ 118,897	$ 445	0.38%
8	Large Power Primary	19P	5	156,308,236	$ 6,240,187	$ 4,586,187	$ 10,826,374	$ 5,107,549	$ 11,347,736	$ 521,361	4.82%
9	Large Power Transmission	19T	1	100,027,107	$ 4,122,106	$ 2,873,801	$ 6,995,907	$ 3,200,081	$ 7,322,188	$ 326,280	4.66%
10	Agricultural Irrigation Service	24	2,337	69,343,194	$ 6,147,123	$ 2,079,370	$ 8,226,493	$ 2,315,453	$ 8,462,576	$ 236,084	2.87%
11	Unmetered General Service	40	2	5,388	$ 253	$ 162	$ 415	$ 180	$ 433	$ 18	4.42%
12	Street Lighting	41	26	329,751	$ 148,035	$ 9,888	$ 157,923	$ 11,011	$ 159,045	$ 1,123	0.71%
13	Traffic Control Lighting	42	13	28,017	$ 2,520	$ 840	$ 3,360	$ 936	$ 3,455	$ 95	2.84%
14	Total Uniform Tariffs		20,239	674,494,965	$ 42,060,311	$ 19,976,489	$ 62,036,799	$ 22,246,128	$ 64,306,438	$ 2,269,639	3.66%
15	Total Oregon Retail Sales		20,239	674,494,965	$ 42,060,311	$ 19,976,489	$ 62,036,799	$ 22,246,128	$ 64,306,438	$ 2,269,639	3.66%

Line No	Tariff Description	Current Billed Revenue w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	2025 March Forecast Proposed Revenue	2025 March Forecast Proposed Adjustments to Billed Revenue	2025 March Forecast Revenue Percent Change	2025 Composite APCU Revenue Adjustment	Proposed Total Billed Revenue	2025 Composite APCU Percent Change
	Uniform Tariff Rates:									
1	Residential Service	$ 21,699,329	$ 1,449,708	$ 23,149,037	$ 285,828	$ (1,163,880)	(5.03)%	$ (508,854)	$ 22,640,183	(2.20)%
2	Residential Service - Time-of-Day Pilot	$ 12,845	$ 913	$ 13,758	$ 179	$ (734)	(5.33)%	$ (343)	$ 13,416	(2.49)%
3	Small General Service	$ 2,511,258	$ 150,396	$ 2,661,654	$ 29,647	$ (120,749)	(4.54)%	$ (52,928)	$ 2,608,726	(1.99)%
4	Large General Secondary	$ 9,688,965	$ 830,306	$ 10,519,271	$ 163,673	$ (666,633)	(6.34)%	$ (292,187)	$ 10,227,083	(2.78)%
5	Large General Primary	$ 1,807,994	$ 167,878	$ 1,975,873	$ 33,091	$ (134,788)	(6.82)%	$ (59,128)	$ 1,916,745	(2.99)%
6	Large General Transmission	$ 234,219	$ 24,140	$ 258,360	$ 4,759	$ (19,382)	(7.50)%	$ (8,493)	$ 249,867	(3.29)%
7	Dusk to Dawn Lighting	$ 118,522	$ 986	$ 119,509	$ 194	$ (792)	(0.66)%	$ (347)	$ 119,162	(0.29)%
8	Large Power Primary	$ 10,910,252	$ 1,154,362	$ 12,064,614	$ 227,587	$ (926,775)	(7.68)%	$ (405,414)	$ 11,659,200	(3.36)%
9	Large Power Transmission	$ 7,049,584	$ 723,347	$ 7,772,931	$ 142,592	$ (580,755)	(7.47)%	$ (254,475)	$ 7,518,456	(3.27)%
10	Agricultural Irrigation Service	$ 8,263,703	$ 523,386	$ 8,787,089	$ 103,174	$ (420,212)	(4.78)%	$ (184,128)	$ 8,602,961	(2.10)%
11	Unmetered General Service	$ 418	$ 41	$ 458	$ 8	$ (33)	(7.13)%	$ (14)	$ 444	(3.12)%
12	Street Lighting	$ 158,100	$ 2,489	$ 160,589	$ 491	$ (1,998)	(1.24)%	$ (876)	$ 159,713	(0.55)%
13	Traffic Control Lighting	$ 3,375	$ 211	$ 3,587	$ 42	$ (170)	(4.73)%	$ (74)	$ 3,512	(2.07)%
14	Total Uniform Tariffs	$ 62,458,565	$ 5,028,164	$ 67,486,728	$ 991,264	$ (4,036,900)	(5.98)%	$ (1,767,260)	$ 65,719,468	(2.62)%
15	Total Oregon Retail Sales	$ 62,458,565	$ 5,028,164	$ 67,486,728	$ 991,264	$ (4,036,900)	(5.98)%	$ (1,767,260)	$ 65,719,468	(2.62)%

(1) Updated June 2025-May 2026 Test Year