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March 25, 2024

VIA E-MAIL TO

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Re: Docket UE 425 - In the Matter of Idaho Power Company, 2024 Annual Power Cost Update.

Attached for filing in the above-referenced docket is Idaho Power Company's 2024 March Forecast, which includes the Direct Testimony of Jessica G. Brady (Idaho Power/300-309).

Please contact this office with any questions.

Sincerely,

Cole Albee

Cole Albee
Paralegal
McDowell Rackner Gibson PC

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 425

IN THE MATTER OF IDAHO POWER COMPANY'S 2024 ANNUAL POWER COST UPDATE	)
MARCH FORECAST	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JESSICA G. BRADY

March 25, 2024

Q. Are you the same Jessica G. Brady who previously submitted testimony in this proceeding?

A. Yes. I previously submitted direct testimony in this proceeding regarding the October Update for the 2024 Annual Power Cost Update ("APCU"). The 2024 October Update is Idaho Power Company's ("Idaho Power" or "Company") estimate of what "normalized" power supply expenses will be for the upcoming APCU test period of April 2024 through March 2025.

Q. What is the status of the October Update in this proceeding?

A. The Company filed the 2024 October Update on October 31, 2023, and the Public Utility Commission of Oregon ("Commission") Staff ("Staff") and the Oregon Citizens' Utility Board ("CUB") reviewed the filing. Nine rounds of discovery requests have been served on the Company since the initial filing. Settlement conferences were held between Idaho Power, Staff, and CUB on January 4 and January 10, 2024. On January 31, Staff filed opening testimony and on February 29, the Company filed reply testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the second part of the Company's APCU filing, which is the March Forecast, as detailed in Order No. 08-238.[1] As mentioned previously, the Company filed the first part of the APCU, the October Update, on October 31, 2023. The initial October Update filing proposed a revenue decrease of $101,556, or a 0.18 percent decrease. If the March Forecast and October Update are approved as filed, the 2024 composite APCU (both the October Update and March Forecast components) will result in a revenue decrease of $6.1 million or a 9.2 percent decrease in billed revenue collection, to become effective June 1, 2024.

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[1] *In the Matter of 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).

Q. What are the main factors driving the revenue change requested in this case?

A. The revenue decrease requested in this case results from a decrease in expected net power supply expense ("NPSE") for the March Forecast, as well as a decrease in normalized NPSE for the October Update, which has been updated since the initial October Update filing.

The requested revenue requirement for the 2024 March Forecast is approximately $4.9 million, which reflects a $6.0 million decrease compared to the current 2023 March Forecast revenue requirement included in Oregon customer rates of $10.9 million. As discussed later in my testimony, the decrease in NPSE for the 2024 March Forecast as compared to last year is largely attributed to an increase in hydro generation and a decrease in forward market electric prices.

For the October Update, the requested revenue requirement decrease is approximately $41,206 as compared to the revenue requirement decrease of $101,556 included in the initial October Update filing. The factors driving the revenue requirement change are updated Energy Imbalance Market ("EIM") benefits and an updated sales and load forecast.

Q. How is your testimony organized?

A. My testimony begins by describing the filing requirements associated with the March Forecast and the differences between the October Update and the March Forecast. Next, my testimony describes the required updates to AURORA. I then present and discuss the forecast of total NPSE for the 2024 March Forecast and how it compares to last year's 2023 March Forecast. My testimony concludes with the quantification of the projected revenue requirement decrease and the proposed rate implementation to allocate the revenue decrease to customers.

Q. Have you prepared exhibits for this proceeding?

A. Yes, I am sponsoring the following exhibits:

1. Exhibit 301, Total normalized base net power supply expense for the 2024 October Update
3. Exhibit 302, AURORA modeled determination of expected power supply expense for the 2024 March Forecast
2. Exhibit 303, Forward price curves used for re-pricing purchased power and surplus sales
3. Exhibit 304, Total expected net power supply expense for the 2024 March Forecast
4. Exhibit 305, Year-over-year differences in March Forecast net power supply expense
5. Exhibit 306, EIM benefits
6. Exhibit 307, EIM costs
7. Exhibit 308, October Update and March Forecast combined rate calculation
8. Exhibit 309, Revenue spread and revenue impact

I. MARCH FORECAST OVERVIEW

Q. What is the March Forecast?

A. The March Forecast is the Company's quantification of the "expected" NPSE for the APCU test period of April through March, as determined by the AURORA model.

Q. How does the March Forecast differ from the October Update?

A. The October Update was calculated by simulating 37 water year conditions in the AURORA model and then averaging the results of all 37 NPSE scenarios to create an "average" or "normal" expectation of NPSE. In contrast, the March Forecast is calculated by simulating the "expected" water condition during the upcoming APCU test period using data derived from the Company's most recent long-term streamflow forecast. The results for the October Update are used to update base rates, while the results for the March Forecast are used to update Schedule 55, Annual Power Cost Update.

II. AURORA MODEL INPUTS

Q. Please describe the variables that are to be updated in the AURORA model for the March Forecast, as described in Order No. 08-238.

A. The following variables, as described in Order No. 08-238, are to be updated in the March Forecast:

a. Fuel prices and transportation costs;
b. Wheeling expenses;
c. Planned outages and equivalent forced outage rates ("EFOR");
d. Heat rates;
e. Forecast of normalized sales and loads, updated only for known significant changes since the October APCU filing;
f. Forecast hydro generation from current reservoir levels and the most recent water supply forecast;
g. Contracts for wholesale power and power purchases and sales;
h. Forward price curve;
i. Public Utility Regulatory Policies Act ("PURPA") contract expenses; and
j. The Oregon state allocation factor.

Q. How do the modeling variables, as described in Order No. 08-238, compare between the 2024 March Forecast and those used to develop the 2024 October Update?

A. All of the modeling variables described in Order No. 08-238 were reviewed for accuracy, and updated where appropriate, in the preparation of the proposed March Forecast. For the April 2024 through March 2025 test period, the following variables changed since the October APCU was prepared: (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 ("ERMP"); (7) forward price curve; and (8) PURPA contract expenses.

A. <u>Fuel Expense</u>.

Q. What fuel cost forecasts were used for the October Update and March Forecast, respectively?

A. When the October Update was prepared, information from September 2023 was used. The March Forecast determination of NPSE includes the Company's most current coal and gas price forecasts from early March 2024.

Q. How do coal fuel expense and coal-fired generation for the March Forecast compare to the October Update results?

A. Total coal fuel expense included in the 2024 March Forecast is $62.9 million, compared to $84.6 million in the 2024 October Update, a decrease of 26 percent. Coal-fired generation also decreased as compared to the October Update, from 2.1 million megawatt-hours ("MWh") to 1.6 million MWh, or approximately 24 percent. Forecast generation at Bridger decreased 22 percent from the October Update and forecast generation at Valmy decreased 33 percent.

Q. What factors are driving the forecast coal-fired generation and expenses at Bridger and Valmy?

A. Forecast coal-fired generation decreased 24 percent compared to last year due to the conversion of Bridger units 1 and 2 to natural gas. Both units are scheduled to be converted to natural gas by spring 2024, and as a result, were modeled as natural gas resources for this test year beginning in April and May, respectively.

Q. Did the Company update its forecast of total OHAG expenses per the terms of the 2016 and 2017 APCU settlement stipulations?

A. Yes. Per the terms of the 2016 APCU settlement stipulation,[2] for the March Forecast, the Company included within the AURORA model the per-MWh OHAG expense driven by Idaho Power's dispatch of each coal plant. The Company separately accounted for its fixed proportional share of the total OHAG expense incurred at each of the coal plants.

Per the terms of the 2017 APCU settlement stipulation ("2017 Stipulation"),[3] the Company is to annually update its fixed proportional share of total forecast OHAG expense incurred at each of the coal plants as part of the March Forecast filing. According to the stipulation, the OHAG forecast should be calculated with a three-year historical average of actual OHAG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate.

For the 2024 March Forecast, Idaho Power updated the OHAG forecast 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 number to a negative number, which is the result of an increase in revenue from fly ash sales. The forecast of total OHAG expense for Bridger and Valmy are displayed on lines 6 and 12 of Exhibit 302, respectively.

Q. Does Idaho Power's 2024 March Forecast account for revenues received from or expenses paid to NV Energy (its ownership partner in the Valmy plant) for use

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

[3] *In the Matter of Idaho Power Company's 2017 Annual Power Cost Update*, Docket No. UE 314, Stipulation at 7 (Apr. 28, 2017).

of the Company's unused capacity or the Company's use of NV Energy's unused capacity in Unit 2?

A. Yes. Per the terms of the 2017 Stipulation, Idaho Power agreed to include the three-year historical average of actual net balances associated with ownership partner use of unused capacity at Valmy Unit 2 as an offset or expense to total NPSE. The Company is to update the three-year historical average as part of the March Forecast. For this year's March Forecast, the Company utilized the three-year average from 2020 – 2022, as the Company is still working with NV Energy to determine the usage charge for 2023. The 2020-2022 historical average net revenue paid to Idaho Power is $71,106 on a system-wide basis, associated with NV Energy's dispatch of Idaho Power's unused capacity at Valmy Unit 2. As shown on line 13 of Exhibit 302, this amount has been reflected as an offset to NPSE for Valmy for the 2024 March Forecast.

Q. How did the gas price forecast included in the March Forecast change as compared to the gas price forecast included in the October Update?

A. The gas price forecast used for the March Forecast for Henry Hub was $3.02 per MMBtu, which is $0.88 lower than the Henry Hub gas price used for the October Update.

Q. How does the Henry Hub price included in this year's March Forecast compare to the price included in last year's March Forecast?

A. The Henry Hub price of $3.02 per MMBtu included in this year's March Forecast is $1.00 per MMBtu lower than the Henry Hub price used in last year's March Forecast, reflecting a 25 percent decrease.

Q. How is the Henry Hub gas price forecast used as an AURORA input?

A. The Company uses the gas price forecast for Henry Hub as the starting point in the AURORA model. Henry Hub is considered a reference fuel in AURORA, meaning other gas market prices are determined by applying an adjustment factor to the Henry Hub price. For example, a Henry Hub gas price of $3.85 per MMBtu applied to a Sumas basis of $0.19 per MMBtu equals a Sumas gas price of $4.04 per MMBtu ($3.85 + $0.19 = $4.04). The Company develops a separate gas price for its natural gas units based upon the Henry Hub gas price forecast, referred to as the Idaho Citygate price and the Bridger Gas price.

Q. Please explain the Idaho Citygate price and the Bridger Gas price.

A. The Idaho Citygate price is representative of the gas price delivered to Langley Gulch, Danskin, and Bennett Mountain. It is based on the Henry Hub price and applies adjustments for Sumas basis and transport costs.

The Bridger Gas price is representative of the gas price delivered to Bridger units 1 and 2. It is based on the Henry Hub price and applies adjustments for Rockies basis and transport costs.

Q. How does the Idaho Citygate price for the 2024 March Forecast compare to last year?

A. The Idaho City Gate price price of $4.64 per MMBtu included in this year's March Forecast is $1.25 per MMBtu lower than the Idaho Citygate price used in last year's March Forecast, reflecting a 21 percent decrease.

Q. What factors are driving the decrease in the Idaho Citygate price?

A. The decrease in the Idaho Citygate price for the 2024 March Forecast is primarily due to a decrease in the Henry Hub price, which is attributable to increased natural gas production and above-average storage inventories, as well as relatively mild-winter temperatures in 2023 and 2024. According to the U.S. Energy Information

Administration ("EIA"), this year's winter heating season ended with natural gas inventories 37 percent higher than the 5-year average.[4]

Q. What is the Bridger Gas price used in this year's March Forecast?

A. The Bridger Gas price for the 2024 March Forecast is $3.80 per MMBtu.

B. PURPA Expense.

Q. Please describe any changes to PURPA generation and expense since the October Update.

A. The October Update included 354.7 average megawatts ("aMW") of available PURPA generation, whereas PURPA generation included in the March Forecast is 335.1 aMW, a decrease of 19.6 aMW, or 5.5 percent. Total PURPA expense included in the March Forecast is $242.9 million compared to $250.3 million included in the October Update, a decrease of $7.5 million, or 3 percent. The decrease is largely due to the removal of two solar projects (Moore's Hollow and Prairie City) from the forecast, as the developers missed their online dates and the agreements for these projects have been terminated.

Q. How does total PURPA generation and expense included in the 2024 March Forecast compare to last year's March Forecast?

A. As mentioned above, this year's March Forecast includes PURPA generation of 335.1 aMW and PURPA expense of $242.9 million. Last year's filed forecast included PURPA generation of 342.2 aMW and PURPA expense of $240.1 million. Compared to last year's settled PURPA expense amount, this year's PURPA forecast is an increase of $9.8 million.

Q. Have there been any changes in the number of PURPA projects since last year?

A. No. There have been no changes in the number of PURPA projects since last year.

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[4] EIA Short-Term Energy Outlook ("STEO"). March 2024.

Q. Does the PURPA forecast included in the 2024 March Forecast include a Contract Delay Rate ("CDR") adjustment per the terms of the 2018 and 2020 APCU settlement stipulations?

A. Yes. Durkee Solar is the only project expected to come online during the test year. This project's revised scheduled operation date with the CDR adjustment is July 17, 2025. As a result, this project was removed from this year's forecast.

C. <u>Normalized Load</u>.

Q. Please explain the change between the forecast of normalized load used in the October Update and the March Forecast.

A. The forecast of system normalized load used for the March Forecast is 1,962 aMW compared to 1,971 aMW for the October Update, a decrease of 9 aMW. Additionally, there was a reallocation of normalized load and billed sales by jurisdiction between the October Update and March Forecast.

D. <u>Hydro Forecast</u>.

Q. What is the basis of the hydro generation forecast for the March Forecast?

A. The forecast of monthly hydro generation levels included in the 2024 March Forecast is based on the Company's long-term stream forecast from February 20, 2024. The forecast has expected inflows into Brownlee Reservoir for April through July of 4.6 million acre-feet ("MAF").

Q. How does this year's water supply forecast compare to last year's forecast?

A. The forecast used in last year's March Forecast included expected inflows into Brownlee Reservoir for April through July of 4.0 MAF compared to this year's forecast of 4.6 MAF, reflecting a 15 percent increase. Expected inflows into Brownlee Reservoir were higher in this year's March Forecast as a result of above normal storage conditions in reservoirs upstream of Idaho Power's hydro system coupled with normal snowpack conditions, which provide for sustained runoff and increased hydro generation during the spring and summer months.

Q. How does the change in expected inflows impact this year's hydro generation forecast compared to last year's forecast?

A. The hydro generation forecasted for this year's March Forecast is 6.9 million MWh compared to 6.4 million MWh in last year's March Forecast, a 9 percent increase.

Q. How does the hydro generation forecast compare to the normalized scenario used for the October Update?

A. The hydro generation forecasted under the normalized scenario (37 water years) for the 2024 October Update was 8.2 million MWh. The hydro generation forecasted for this year's March Forecast is 6.9 million MWh, a decrease of 1.3 million MWh or 16 percent as compared to the October Update, which suggests that the expected hydro generation for the 2024 March Forecast is below normal.

E. Known Power Purchases and Surplus Sales.

Q. Did the Company include known power purchases and surplus sales resulting from the Company's ERMP in the March Forecast?

A. Yes. As directed by Order No. 08-238, the Company includes known power purchases and surplus sales resulting from the Company's ERMP and incorporates those amounts as net hedges as can be seen on lines 46 and 47 of Exhibit 302. Known power purchases and surplus sales are not included in the October Update of the APCU.

F. Re-Pricing Based on a Forward Price Curve.

Q. How are market power purchases and sales calculated for the March Forecast portion of the APCU?

A. Per Order No. 21-165, the wholesale electric prices for purchased power and surplus sales determined by the AURORA model are replaced with an average forward electric price curve.[5]

Q. Please describe the re-pricing methodology mentioned above.

A. The Company is required 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. This methodology prescribes the use of the most recent monthly forward price curve for the April through March t est period.

Q. Did Idaho Power apply this pricing methodology to the March Forecast?

A. Yes. Exhibit 303 shows the March 13, 2024, Mid-C HL and LL forward price curve for the April 2024 through March 2025 test period that the Company used to re-price purchased power and surplus sales for the 2024 March Forecast.

Q. Are there additional steps in the re-pricing of AURORA generated power purchases and surplus sales for the March Forecast?

A. Yes. To determine the portions of power purchases and sales that occur in HL and LL hours (to which the forward price curve is applied), the Company extracts hourly purchases and sales determined by the AURORA model. The portions of AURORA-generated HL and LL purchases and sales for the 2024 March Forecast are shown on lines 54, 56, 58, and 60 of Exhibit 304.

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[5] *In the Matter of Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism*, Docket No. UE 384, Order No. 21-165 (May. 27, 2021).

Q. How does the re-pricing of purchased power and surplus sales, using a forward price curve, change purchased power expenses and surplus sales revenues as modeled by AURORA?

A. The monthly Mid-C HL and LL forward price curve, from Exhibit 303, is applied to the AURORA-generated proportions of HL and LL purchases and sales to determine re-priced purchased power expense and surplus sales revenue for the March Forecast, which can be seen on lines 24 and 42 of Exhibit 304. As shown in columns I and J of Exhibit 305, for this year's March Forecast, re-pricing of market purchases and sales results in a net increase in NPSE of $100.9 million on a system basis. The re-pricing of purchased power using a forward price curve increased the average market purchase price of $39.86 per MWh (as modeled in AURORA) to $88.97 per MWh, resulting in a $120.8 million increase in NPSE on a system basis. The re-pricing of surplus sales increased the average market sales price of $35.79 per MWh (as modeled in AURORA) to $65.24 per MWh, resulting in an increase in surplus sales revenue of $19.9 million on a system basis.

III. <u>2024 FORECAST NPSE</u>

Q. Have you prepared an exhibit that summarizes the total NPSE for the March Forecast?

A. Yes. Exhibit 304 shows the results of the AURORA modeling determination of forecast NPSE, as well as the re-pricing of market purchases and surplus sales and total PURPA expense for the April 2024 through March 2025 test year.

Q. What is the Company's March Forecast of NPSE as a result of the changes described above?

A. Exhibit 304 shows the results of a single water condition for the April 2024 through March 2025 test period, with updated fuel prices, normalized load, updated stream flow conditions, updated power purchases, and surplus sales from the Company's

ERMP (net hedges), market purchased power and surplus sales re-priced, and updated PURPA contract expenses. The March Forecast of NPSE without PURPA expenses is $413.1 million. When PURPA expenses of $242.9 million and EIM benefits of $48.1 million are included, total NPSE for the March Forecast is $607.9 million. A discussion of EIM benefits is included later in testimony.

Q. How does the 2024 March Forecast of NPSE compare to last year's March Forecast of NPSE?

A. The 2024 March Forecast of NPSE is $607.9 million, or $148.7 million less than the 2023 March Forecast of NPSE of $756.5 million.[6]

Q. How does the modeled generation in the 2024 March Forecast compare to last year's March Forecast?

A. To illustrate the changes in generation, Columns D (2023) and F (2024) of Exhibit 305 calculate the percentage of generation compared to total system load. For example, Column F, line 1, shows that hydro provided 40 percent of the generation to meet the total system load of 17,187,465 MWh (6,941,080 / 17,187,465 = 40 percent) compared to 37 percent in the 2023 March Forecast. Coal generation decreased from 12 percent to 9 percent, natural gas generation increased from 8 percent to 18 percent, market purchased power decreased from 20 percent to 14 percent, PPA generation increased from 5 percent to 7 percent, PURPA generation decreased from 18 percent to 17 percent, and lastly, surplus sales increased from 3 percent to 7 percent. This comparison between resource type and total system load shows that reduced coal generation and market purchases is being met with increased natural gas and PPA generation. In addition, the increase in natural gas and PPA generation resulted in increased opportunity to make economic off-system sales.

[6] *In the Matter of Idaho Power Company's 2023 Annual Power Cost Update,* Docket No. UE 414, Stipulation, Exhibit 2 at 1-2 (May 3, 2023).

Q. Are the relative changes in expenses between resource types consistent with the changes in output?

A. The relative changes in expenses between resource types are mostly consistent with the changes in output. The changes in expenses shown in columns D (2023) and F (2024) of Exhibit 305 are as follows: coal fuel expense remained unchanged at 10 percent of total expense; natural gas expense increased from 6 percent to 22 percent; market purchased power expense decreased from 51 percent to 36 percent; PPA expense increased from 7 percent to 11 percent; PURPA expense increased from 31 percent to 40 percent; and surplus sales revenue increased from negative 6 percent to negative 13 percent.

Q. Please summarize the factors driving the change in NPSE as compared to last year's March Forecast.

A. The increase in hydro generation combined with the decrease in forward market prices resulted in a 19 percent decrease in total forecast NPSE compared to last year's March Forecast.

A. <u>EIM Costs and Benefits</u>.

Q. Has the Company adjusted the NPSE amounts included in the 2024 APCU to reflect Idaho Power's participation in the Western EIM?

A. Yes. The NPSE requested for approval in the 2024 APCU includes both the incremental benefits and costs associated with Idaho Power's participation in the Western EIM. However, because EIM costs were included in the test year for the Company's currently open general rate case, UE 426, with a requested rate effective date of October 15, 2024, [7] it has included EIM-related costs in the APCU for just the

[7] *In the Matter of Idaho Power Company's Request for a General Rate Revision*, Docket No. UE 426.

period April 1, 2024 - October 14, 2024. In addition, EIM costs will not be included in subsequent APCU filings once they are included in the Company's base rates.

Q. What level of EIM benefits is Idaho Power proposing to include in the 2024 APCU?

A. Idaho Power is proposing to include $48.1 million in system EIM benefits as an offset to NPSE in the 2024 APCU, as shown on Lines 55 and 47 of Exhibits 301 and 304, respectively. On an Oregon allocated basis, the EIM benefits to be included in the 2024 APCU total $2.0 million.

Q. How does this compare to the level of EIM benefits included in the 2024 October Update?

A. The level of benefits included in this year's March Forecast (on a system-level) is $0.3 million, or 0.7 percent, less than the level of benefits included in the October Update.

Q. Please describe the data used in the EIM benefit calculation.

A. As described in my Opening Testimony, Idaho Power's EIM benefit calculation utilizes the CAISO report of EIM benefits as a starting point, and then accounts for necessary adjustments to quantify ongoing cost savings benefits specific to Idaho Power's participation in the EIM. These adjustments include a modification to the CAISO methodology as it pertains to the hydro pricing cost structure. The Company updated its EIM benefit calculation using the most recent 12-months of EIM benefit data from CAISO, which includes data for February 2023 – January 2024. Exhibit 306 presents Idaho Power's EIM benefit forecast for the 2024 APCU.

Q. What is driving the change in the EIM benefits forecast from the prior year?

A. The increased level of benefits for the 2024 APCU is largely attributable to a one-time issue with pricing used for Bridger in April and May of 2023 that will not exist into the future due to the conversion of Bridger Units 1 and 2 to natural gas in the first half of 2024.

Q. Did the Company update the estimated EIM costs to be included in the 2024 APCU?

A. Yes. The Company updated the annual revenue requirement associated with the EIM-related costs to be included in the 2024 APCU. On an Oregon-allocated basis, the revenue requirement associated with EIM costs to be included in the 2024 APCU is $64,289, as shown in Exhibit 307.

B. Per-Unit Cost Calculation and Quantification of the Revenue Requirement Impact.

Q. What is the March Forecast unit cost per MWh for this filing?

A. Exhibit 304 shows total system NPSE of $607.9 million and normalized annual sales at the customer level for the April 2024 through March 2025 test year, net of Black Mesa Solar's generation and Lamb Weston Surplus Sales, of 15,736,664 MWh, resulting in a per-unit cost for the 2024 March Forecast of $38.63 per MWh ($607.9 million / 15.737 million MWh = $38.63 per MWh) to become effective on June 1, 2024.

Q. How does this year's March Forecast unit cost per MWh compare to last year's March Forecast unit cost per MWh?

A. The 2023 March Forecast unit cost per MWh was $48.36 per MWh ($756.5 million / 15.643 million MWh = $48.36 per MWh), compared to this year's March Forecast unit cost of $38.63 per MWh.

Q. Please describe the calculation necessary to determine the March Forecast rate.

A. Exhibit 308 steps through the Commission-specified method of calculating the March Forecast rate, pursuant to Order No. 08-238. Lines 1-3 show the calculation for the October Update unit cost of $30.78 per MWh. Lines 4-6 show the calculation for the March Forecast unit cost of $38.63 per MWh. Line 7 reflects the March Forecast unit cost minus the October Update unit cost multiplied by the March Forecast Normalized Sales (line 6 minus line 3 multiplied by line 4). Line 8 is the allocated amount (95 percent) that is allowed for the March Forecast rate. Line 9, the Forecast Change Allowed, is calculated by multiplying line 7 by line 8. Line 10 divides line 9 by line 4 to calculate the March Forecast rate of $7.46 per MWh.

Q. How does the $7.46 per MWh compare to the March Forecast rate that resulted from last year's computation?

A. The March Forecast rate for last year's April 2023 through March 2024 test period was $16.68 per MWh, as compared to this year's April 2024 through March 2025 test period rate of $7.46 per MWh, a decrease of $9.22 per MWh.

Q. How is the revenue requirement for the March Forecast calculated using the March Forecast rate unit cost of $7.46 per MWh?

A. The revenue requirement for the March Forecast is calculated by multiplying the March Forecast rate of $7.46 per MWh by the loss-adjusted Oregon jurisdictional sales for the April 2024 through March 2025 test period of 656,167.451 MWh, resulting in a revenue requirement of approximately $4.9 million, as shown on page 2 of Exhibit 309, line 1. Under the current March Forecast rate of $16.68 per MWh, the revenue requirement included in Oregon customer rates is approximately $10.9 million. As such, the proposed 2024 March Forecast rate of $7.46 per MWh will result in a revenue requirement decrease of $6.0 million compared to what is currently being collected through Oregon customer rates.

Q. Did the Company revise the revenue requirement for the October Update?

A. Yes. The Company revised the revenue requirement for the 2024 October Update to align with the loss-adjusted sales that were used for the March Forecast filing. In addition, Idaho Power updated the EIM benefits to reflect the most recent data available.

The practice of updating the loss-adjusted sales for the October Update revenue requirement is consistent with the method applied in all previous APCU filings.

The April 2024 through March 2025 loss-adjusted Oregon jurisdictional sales for the October Update were 681,006.975 MWh, whereas the loss-adjusted Oregon jurisdictional sales for the March Forecast are 656,167.451 MWh, a decrease of 24,839.524 MWh. The change in the loss-adjusted sales, as well as the EIM benefit number, increases the October Update revenue requirement from an initial decrease of $101,556 to a decrease of $41,206. Exhibit 309 contains the revised October Update revenue requirement.

IV. RATE IMPLEMENTATION

Q. What method of allocation are you proposing to spread the revenue requirement decrease associated with the 2024 APCU to the various customer classes?

A. The Company proposes to allocate the revenue requirement associated with the 2024 APCU according to the revenue spread methodology agreed upon in the 2018 Stipulation. The 2018 Stipulation established a revenue spread methodology whereby the APCU revenue requirement is allocated to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the test period. Additionally, any rate increases resulting from application of this revenue spread methodology as applied to a customer class will be capped at 3 percent above the overall average rate increase on a percentage of total revenue basis. In this case, the overall average rate change is a decrease, so the revenue cap does not apply.

Q. What is the overall revenue impact of this year's combined October Update and March Forecast compared to last year's combined October Update and March Forecast using the rate spread methodology described above?

A. Exhibit 309 provides a summary of the revenue change resulting from this year's combined October Update and March Forecast as compared to current revenue. As can be seen in Exhibit 309, the overall revenue impact of this year's combined October Update and March Forecast is a decrease of $6.1 million or 9.2 percent overall. The

$6.1 million decrease reflects a decrease of $41,206 in base rate revenues associated with the October Update and a $6.0 million decrease in Schedule 55 revenues associated with the March Forecast.

Q. Does the Company intend to provide supporting workpapers for the 2024 March Forecast to Staff and CUB?

A. Yes. Idaho Power will provide its supporting workpapers to Staff and CUB within five business days of filing the 2024 March Forecast.

Q. Does this conclude your testimony?

A. Yes, it does.

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UE 425

IDAHO POWER COMPANY

Exhibit 301

Total Normalized Base Net Power Supply Expense for the 2024 October Update

March 25, 2024

IDAHO POWER COMPANY NORMALIZED POWER SUPPLY EXPENSES FOR APR L 1, 2024 -- MARCH 31, 2025 (Multiple Gas Prices/37 Hydro Year Conditions)
Repriced Using UE 195 and 384 Settlement Methodology - 2024 October Update
AVERAGE

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	834,153.8	870,903 5	828,403.4	733,139.6	604,718.6	565,857.1	461,336.2	415,272.5	577,363 9	772,382.1	757,438.8	803,032.1	8,224,001 6
Bridger													
Energy (MWh)	78,676.6	43,194.7	29,707.1	135,250.7	156,657.2	119,000 9	129,756.1	223,255.2	247,453 9	192,735.3	214,106.2	45,287.0	1,615,080 9
Expense ($ x 1000)	$ 2,921 5	$ 1,804.3	$ 1,350.3	$ 4,757.8	$ 5,444 5	$ 4,215.2	$ 4,581.4	$ 7,560.1	$ 8,357 9	$ 6,955.9	$ 7,610.3	$ 1,925 5	$ 57,484.5
Valmy													
Energy (MWh)	20,829.0	27,633.7	35,768.1	43,591.7	43,201 8	37,069.6	29,297.4	41,337.1	58,827 2	46,060.4	47,011.8	37,385.7	468,013 5
Expense ($ x 1000)	$ 1,354.3	$ 1,711 2	$ 2,107.4	$ 2,478.3	$ 2,456 6	$ 2,160.5	$ 1,786.8	$ 2,345.1	$ 3,180 6	$ 2,652.8	$ 2,689.4	$ 2,234 8	$ 27,157.9
Bridger Gas													
Energy (MWh)	17,734 00	53,924.42	74,312.89	83,875 84	86,529.94	72,290.78	67,114.86	51,169 09	25,689.87	22,380.43	21,498.32	59,865.76	636,386 2
Expense ($ x 1000)	$ 1,233.3	$ 2,766 0	$ 3,594.0	$ 4,642.2	$ 4,834 0	$ 4,054.2	$ 3,725.9	$ 3,957.2	$ 3,783.4	$ 3,745.0	$ 3,388.4	$ 4,318 9	$ 44,042.4
Langley Gulch													
Energy (MWh)	143,490.4	183,219.7	195,458.6	212,035.0	216,097.2	198,344 8	201,824.3	115,633.8	40,761.1	61,929.3	108,116.9	155,133.1	1,832,044 2
Expense ($ x 1000)	$ 4,488.1	$ 4,672.8	$ 5,190.3	$ 7,067.7	$ 7,482 0	$ 6,583.0	$ 6,485.9	$ 6,849.9	$ 3,017.3	$ 4,835.7	$ 7,935.9	$ 7,864 0	$ 72,472.5
Danskin													
Energy (MWh)	36,386.5	30,593 5	29,181.2	35,384.3	34,753 5	27,858.7	28,674.7	21,054.0	22,397 2	13,644.7	17,969.1	38,810.9	336,708.1
Expense ($ x 1000)	$ 1,614 3	$ 1,093.5	$ 1,112.6	$ 1,802.0	$ 1,853.7	$ 1,374.0	$ 1,363.7	$ 1,963.6	$ 2,715 8	$ 1,652.3	$ 2,049.1	$ 3,030.7	$ 21,625.5
Bennett Mountain													
Energy (MWh)	21,995.8	20,172 0	19,348.7	22,762.7	22,373 6	18,633.5	19,112.7	15,049.3	17,764.1	13,050.4	16,512.5	24,795.6	231,570.7
Expense ($ x 1000)	$ 955 2	$ 701.3	$ 718.3	$ 1,126.0	$ 1,159 2	$ 897.1	$ 884.6	$ 1,351.6	$ 2,086 6	$ 1,545.3	$ 1,858.0	$ 1,892 2	$ 15,175.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 835 8	$ 849.0	$ 835.8	$ 853.7	$ 858 5	$ 831.1	$ 858.5	$ 835 8	$ 853.7	$ 858.5	$ 785.8	$ 858 5	$ 10,114.8
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	40,572.5	39,307 0	119,908.9	238,528.6	192,766.3	54,908.4	33,862.4	102,277.9	191,405 0	122,397.4	43,426.7	68,634 6	1,247,995 5
Elkhorn Wind Energy (MWh)	26,142.4	26,302 5	24,515.6	28,797.5	25,165.1	19,376.0	21,070.2	26,306.7	30,330 8	33,465.9	23,489.1	25,537.4	310,499.1
Jackpot Solar Energy (MWh)	7,871.4	14,384 5	20,427.1	25,685.1	29,177.1	33,777 8	33,025.7	27,862.3	23,505 0	18,009.1	9,518.0	7,147 6	250,390.7
Neal Hot Springs Energy (MWh)	8,524.8	9,916 3	12,648.3	16,278.7	19,120.0	19,165 9	19,441.7	18,897.0	18,338.7	17,194.5	12,566.6	11,833.6	183,926 0
Raft River Geothermal Energy (MWh)	6,669.5	6,986.7	6,984.7	7,674.2	8,195 5	8,238.1	8,560.0	8,468.1	8,541 8	6,952.7	6,689.0	6,858.5	90,819 0
Black Mesa Solar Energy (MWh)	3,096.9	5,659 5	8,036.9	10,105.5	11,479.4	13,289 5	12,993.6	10,962.1	9,247 8	7,085.5	3,744.8	2,812.2	98,513.7
Franklin Solar Energy (MWh)	23,798.4	28,813.4	32,016.5	33,016.7	29,568.5	25,740 0	19,727.6	11,995.9	10,810.5	12,855 5	15,220.6	21,353.9	264,917 5
Pleasant Valley Solar Energy (MWh)	15,823.3	25,932 9	37,984.6	51,014.0	56,229 0	62,369.8	64,005.9	54,817.6	46,942 6	33,234.4	15,795.4	14,145.9	478,295 3
Total Energy Excl. PURPA (MWh)	132,499.2	157,302 8	262,522.5	411,100.4	371,700.9	236,865 5	212,687.1	261,587.5	339,122 2	251,195.2	130,450.1	158,323.6	2,925,356 9
Market Expense ($ x 1000)	$ 1,959.4	$ 1,756.7	$ 5,442.2	$ 27,353.0	$ 27,102.2	$ 6,499.2	$ 2,412.9	$ 7,929.3	$ 17,297.7	$ 11,589.6	$ 3,511.5	$ 4,477 3	$ 117,331 0
Elkhorn Wind Expense ($ x 1000)	$ 1,976.6	$ 1,988.7	$ 1,853.6	$ 2,177.4	$ 1,902.7	$ 1,465.0	$ 1,593.1	$ 1,989.1	$ 2,293 3	$ 2,530.4	$ 1,776.0	$ 1,930 9	$ 23,476.8
Jackpot Solar Expense ($ x 1000)	$ 174.4	$ 318.6	$ 452.5	$ 568.9	$ 646.3	$ 748.2	$ 731.5	$ 617 2	$ 520.6	$ 398.9	$ 210.8	$ 158 3	$ 5,546.1
Neal Hot Springs Expense ($ x 1000)	$ 1,069 9	$ 1,244.6	$ 1,587.5	$ 2,043.1	$ 2,399 8	$ 2,405.5	$ 2,440.1	$ 2,371.8	$ 2,301.7	$ 2,158.1	$ 1,577.2	$ 1,485 2	$ 23,084.6
Raft River Geothermal Expense ($ x 1000)	$ 470 9	$ 493.3	$ 493.2	$ 541 9	$ 578.7	$ 581.7	$ 604.4	$ 597 9	$ 603.1	$ 490.9	$ 472.3	$ 484.3	$ 6,412.7
Black Mesa Solar Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Franklin Solar Expense ($ x 1000)	$ 696.1	$ 842.8	$ 936.5	$ 965.7	$ 864.9	$ 752.9	$ 577.0	$ 350 9	$ 316.2	$ 376.0	$ 445 2	$ 624.6	$ 7,748.8
Pleasant Valley Solar Expense ($ x 1000)	$ 249 9	$ 24.0	$ 3,012.7	$ 2,509.0	$ 1,575 3	$ 1,271.6	$ 1,033.0	$ 746 0	$ 379.0	$ 763.6	$ 929 6	$ 1,629.7	$ 14,123.4
Total Expense Excl. PURPA ($ x 1000)	$ 6,597 3	$ 6,668.7	$ 13,778.2	$ 36,159.0	$ 35,069 8	$ 13,724.0	$ 9,392.0	$ 14,602.1	$ 23,711.7	$ 18,307.5	$ 8,922.7	$ 10,790.4	$ 197,723.5
Storage													
Black Mesa Battery Energy (MWh)	(401.34)	(534.50)	(524 88)	(737.26)	(826.69)	(730 23)	(703.83)	(650.43)	(654.15)	(625 81)	(419.17)	(387.56)	(7,195.85)
80 MW Hemingway Battery Energy (MWh)	(2,583.01)	(2,215.72)	(1,735 55)	(1,750.59)	(1,749.22)	(1,856.94)	(2,537 81)	(2,458.93)	(2,465.71)	(2,794 26)	(2,546.49)	(2,868.52)	(27,562.75)
11 MW Grid Battery Energy (MWh)	(262.10)	(228.73)	(188.53)	(216.55)	(234.02)	(223 85)	(282.44)	(258.98)	(269.73)	(289 27)	(249.57)	(301.38)	(3,005.15)
Franklin Battery Energy (MWh)	(1,481.19)	(1,283.50)	(977.60)	(1,178.17)	(1,283.72)	(1,257.39)	(1,581 20)	(1,426.76)	(1,552.94)	(1,628 38)	(1,495.36)	(1,808.89)	(16,955.10)
36 MW Hemingway Battery Energy (MWh)	(875.55)	(759.21)	(595.12)	(706.45)	(768.77)	(745 00)	(944.23)	(849.37)	(915.56)	(951 37)	(870.97)	(1,070.00)	(10,051.60)
Total Storage (MWh)	(5,603.19)	(5,021.66)	(4,021 68)	(4,589.02)	(4,862.42)	(4,813.41)	(6,049 51)	(5,644.47)	(5,858.09)	(6,289 09)	(5,581.56)	(6,436.35)	(64,770.45)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Franklin Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36 MW Hemingway Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	4,917.5	10,748.8	1,542 3	-	-	-	-	-	-	-	17,208.6
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
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
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Sales													
Energy (MWh)	326,032.7	288,002 0	162,568.9	35,193.5	53,124 5	184,167.7	228,570.6	109,921.8	64,142.7	137,165.0	223,416.5	252,572.4	2,064,878.1
Revenue ($ x 1000)	$ 15,700.6	$ 12,547.2	$ 6,866.3	$ 4,132.9	$ 7,514.4	$ 21,984.2	$ 15,878.4	$ 8,524.1	$ 5,831.2	$ 12,833.7	$ 18,101.9	$ 16,803.4	$ 146,718.3
Surplus Sales - Third Party Transmission Losses ($ x 1000)	$ 755 9	$ 706.2	$ 863.0	$ 1,117.3	$ 1,145 5	$ 1,002.5	$ 965.4	$ 1,130.7	$ 1,511.9	$ 1,288.9	$ 1,266.4	$ 1,079 2	$ 12,832.96
Lamb Weston Surplus Sales ($ x 1000)	$ 248.06	$ 256.33	$ 301.44	$ 311.49	$ 403.64	$ 283 86	$ 325.77	$ 378.06	$ 390.66	$ 321 23	$ 351.69	$ 389.37	$ 3,961.6
Net Power Supply Expenses ($ x 1000)	$ 3,295 3	$ 6,757.2	$ 20,656.2	$ 53,325.0	$ 50,094.7	$ 10,568.5	$ 11,909.3	$ 29,432.6	$ 39,973.4	$ 26,109.1	$ 15,519.5	$ 14,642 9	**$ 282,283.7**
PURPA ($ x 1000)	$ 18,663.1	$ 21,029.4	$ 25,750.8	$ 28,863.9	$ 28,500 3	$ 20,754.3	$ 17,709.1	$ 17,120.2	$ 18,207 0	$ 16,920.7	$ 20,001.1	$ 16,805.4	$ 250,325.4
EIM Benefits ($ x 1000)													$ 48,085.50
Total Net Power Supply Expenses ($ x 1000)	$ 21,958.4	$ 27,786 6	$ 46,407.0	$ 82,188.9	$ 78,595.1	$ 31,322.8	$ 29,618.5	$ 46,552.8	$ 58,180.4	$ 43,029.8	$ 35,520.7	$ 31,448 3	**$ 484,523.6**
Sales at Customer Level (In 000s MWH)	1,115.43	1,167.63	1,308.38	1,623 90	1,721.08	1,518.05	1,169.71	1,106 01	1,258.72	1,379.53	1,311 53	1,225.84	15,905.826
Lamb Weston kWh Sales (In 000s MWH)	4.23	4 37	5.14	5.31	6.88	4 84	5.55	6.44	6 66	5.47	5.99	6.63	67.496
Sales at Customer Level - Net Black Mesa Solar & LW (In 000s MWH)	1,108.11	1,157.61	1,295.21	1,608.48	1,702.72	1,499.92	1,151.17	1,088.61	1,242.82	1,366.97	1,301 80	1,216.40	15,739.816
Hours in Month	720	744	720	744	744	720	744	721	744	744	672	743	8,760
Unit Cost / MWH (for PCAM)	$19.82	$24.00	$35 83	$51.10	$46.16	$20 88	$25.73	$42.76	$46.81	$31.48	$27.29	$25.85	**$30.78**
Prices Used in Purchased Power & Surplus Sales Above													
Heavy Load													
Portion of Purchased Power considered HL Purchases	**58.58%**	58.77%	67.98%	56.40%	64 29%	61.76%	70.56%	60.49%	59.25%	60.36%	56.26%	48 90%	
Purchased Power HL Price	$51.98	$49.53	$51 08	$142 58	$166.20	$140.40	$74.73	$82.77	$97.07	$103.55	$88.69	$72.27	
Portion of Surplus Sales considered HL Surplus Sales	**57.04%**	49.18%	50.27%	60.71%	65.48%	63.50%	55.45%	60 64%	62.52%	55.33%	57.16%	58 31%	
Surplus Sales HL Price	$51.98	$49.53	$51 08	$142 58	$166.20	$140.40	$74.73	$82.77	$97.07	$103.55	$88.69	$72.27	
Light Load													
Portion of Purchased Power considered LL Purchases	**41.42%**	41.23%	32.02%	43.60%	35.71%	38.24%	29.44%	39 51%	40.75%	39.64%	43.74%	51.10%	
Purchased Power LL Price	$43.08	$37.80	$33 29	$78.58	$94.50	$82.79	$62 91	$69.50	$80.63	$81.19	$70.79	$58.51	
Portion of Surplus Sales considered LL Surplus Sales	**42.96%**	50.82%	49.73%	39.29%	34 52%	36.50%	44.55%	39 36%	37.48%	44.67%	42.84%	41 69%	
Surplus Sales LL Price	$43.08	$37.80	$33 29	$78.58	$94.50	$82.79	$62 91	$69.50	$80.63	$81.19	$70.79	$58.51	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 302

AURORA Modeled Determination of Expected Power Supply Expense for the
2024 March Forecast

March 25, 2024

IDAHO POWER COMPANY EXPECTED POWER SUPPLY EXPENSE FOR APRIL 1, 2024 -- MARCH 31, 2025 (One Hydro Condition)
2024 APCU March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	728,482.2	952,853.5	828,672.3	598,407.3	517,282.4	487,846.2	414,823.0	366,558.3	422,976.1	472,850.5	497,229.6	653,098.6	6,941,080.0
	Bridger													
2	Energy (MWh)	29,071.2	31,210.8	45,311.1	91,460.9	104,770.7	76,109.4	53,647.0	137,828.4	239,243.3	204,422.4	221,585.2	27,072.1	1,261,732.4
3	AURORA Modeled Expense ($ x 1000)	$ 1,464.0	$ 1,547.9	$ 1,951.2	$ 3,355.9	$ 3,755.2	$ 2,875.5	$ 2,221.1	$ 4,727.4	$ 7,790.6	$ 6,742.3	$ 7,197.8	$ 1,374.5	$ 45,003.3
4	AURORA Modeled Handling Expense ($ x 1000)	$ (17.2)	$ (18.4)	$ (26.7)	$ (54.0)	$ (61.8)	$ (44.9)	$ (31.7)	$ (81.3)	$ (141.2)	$ (120.6)	$ (130.7)	$ (16.0)	$ (744.4)
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 1,481.1	$ 1,566.3	$ 1,977.9	$ 3,409.8	$ 3,817.1	$ 2,920.4	$ 2,252.8	$ 4,808.8	$ 7,931.7	$ 6,862.9	$ 7,328.5	$ 1,390.4	$ 45,747.7
6	IPC Share of OHAG Expense ($ x 1000)	$ (326.0)	$ (326.0)	$ (326.0)	$ (326.0)	$ (326.0)	$ (326.0)	$ (326.0)	$ (326.0)	$ (326.0)	$ (326.0)	$ (326.0)	$ (326.0)	$ (3,911.6)
7	Total Expense ($ x 1000)	$ 1,155.1	$ 1,240.3	$ 1,652.0	$ 3,083.9	$ 3,491.1	$ 2,594.4	$ 1,926.8	$ 4,482.8	$ 7,605.8	$ 6,536.9	$ 7,002.6	$ 1,064.5	$ 41,836.1
	Valmy													
8	Energy (MWh)	157.8	12,231.3	24,581.0	31,232.5	29,105.7	26,080.3	25,054.4	18,583.7	38,583.3	38,714.1	40,706.2	26,356.5	311,386.7
9	AURORA Modeled Expense ($ x 1000)	$ 8.9	$ 686.7	$ 1,380.1	$ 1,756.7	$ 1,636.1	$ 1,464.3	$ 1,406.7	$ 1,043.4	$ 2,192.2	$ 2,195.8	$ 2,312.7	$ 1,481.5	$ 17,565.4
10	AURORA Modeled Handling Expense ($ x 1000)	$ 0.4	$ 27.5	$ 55.3	$ 70.3	$ 65.5	$ 58.7	$ 56.4	$ 41.8	$ 86.8	$ 87.1	$ 91.6	$ 59.3	$ 700.6
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 8.5	$ 659.2	$ 1,324.8	$ 1,686.5	$ 1,570.7	$ 1,405.6	$ 1,350.3	$ 1,001.6	$ 2,105.4	$ 2,108.7	$ 2,221.1	$ 1,422.2	$ 16,864.8
12	IPC Share of OHAG Expense ($ x 1000)	$ 357.9	$ 357.9	$ 357.9	$ 357.9	$ 357.9	$ 357.9	$ 357.9	$ 357.9	$ 357.9	$ 357.9	$ 357.9	$ 357.9	$ 4,294.7
13	Usage Charges Paid to IPC ($ x 1000)	$ (5.9)	$ (5.9)	$ (5.9)	$ (5.9)	$ (5.9)	$ (5.9)	$ (5.9)	$ (5.9)	$ (5.9)	$ (5.9)	$ (5.9)	$ (5.9)	$ (71.1)
14	Total Expense ($ x 1000)	$ 360.5	$ 1,011.2	$ 1,676.8	$ 2,038.4	$ 1,922.6	$ 1,757.6	$ 1,702.3	$ 1,353.6	$ 2,457.4	$ 2,460.7	$ 2,573.1	$ 1,774.2	$ 21,088.4
	Bridger Gas													
15	Energy (MWh)	26,225.52	55,464.87	68,750.68	101,488.20	89,906.72	86,093.85	76,846.46	26,088.89	21,210.70	21,966.47	34,024.41	100,069.54	708,136.3
16	Expense ($ x 1000)	$ 785.9	$ 1,567.6	$ 2,119.2	$ 3,769.1	$ 3,716.3	$ 3,173.6	$ 2,709.3	$ 2,368.9	$ 3,698.2	$ 3,718.8	$ 3,733.3	$ 4,806.8	$ 36,167.0
	Langley Gulch													
17	Energy (MWh)	161,767.6	198,626.6	206,711.8	225,267.5	213,849.1	219,370.0	208,238.7	90,668.2	-	23,280.7	117,833.4	183,816.9	1,849,430.3
18	Expense ($ x 1000)	$ 3,114.2	$ 3,043.4	$ 3,673.8	$ 5,408.8	$ 5,740.0	$ 5,234.7	$ 5,334.9	$ 4,986.1	$ -	$ 2,283.7	$ 8,878.3	$ 7,115.1	$ 54,813.0
	Danskin													
19	Energy (MWh)	27,124.4	27,169.1	31,833.2	53,607.9	44,270.7	24,099.6	21,874.6	12,000.1	17,480.4	4,252.3	26,022.1	61,947.7	351,681.9
20	Expense ($ x 1000)	$ 659.7	$ 557.4	$ 803.0	$ 1,892.1	$ 1,782.8	$ 900.6	$ 866.3	$ 1,019.3	$ 2,476.3	$ 616.4	$ 3,108.4	$ 3,688.4	$ 18,370.9
	Bennett Mountain													
21	Energy (MWh)	13,424.9	13,618.2	28,593.2	39,858.2	34,610.2	13,449.9	13,347.3	12,502.2	13,593.7	9,110.7	19,280.0	32,850.7	244,239.2
22	Expense ($ x 1000)	$ 331.2	$ 279.9	$ 693.6	$ 1,365.1	$ 1,341.1	$ 499.5	$ 527.5	$ 1,077.5	$ 1,995.9	$ 1,289.5	$ 2,286.4	$ 1,949.9	$ 13,637.1
23	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 788.1	$ 809.5	$ 788.1	$ 809.5	$ 809.5	$ 788.1	$ 809.5	$ 788.1	$ 809.5	$ 809.5	$ 745.1	$ 809.5	$ 9,564.2
	Purchased Power (Excluding PURPA) & Storage													
24	Market Energy (MWh)	18,915.1	23.5	53,363.8	323,409.7	350,678.2	184,253.1	150,300.6	337,924.9	487,364.2	415,662.7	108,090.9	29,631.8	2,459,618.5
25	Elkhorn Wind Energy (MWh)	26,216.7	24,026.0	22,285.3	29,179.9	23,664.5	19,308.9	22,162.8	26,913.8	30,117.8	34,846.6	26,233.9	26,171.1	311,127.3
26	Jackpot Solar Energy (MWh)	27,457.8	32,110.1	32,520.8	34,973.0	30,108.1	25,357.3	20,587.5	10,947.9	6,685.9	9,305.5	14,678.9	23,628.2	268,361.0
27	Neal Hot Springs Energy (MWh)	16,640.0	13,913.1	11,452.0	8,809.0	9,916.5	12,544.9	16,105.9	18,425.7	19,805.0	19,441.9	17,637.4	18,338.9	183,030.3
28	Raft River Geothermal Energy (MWh)	6,728.6	7,406.0	6,637.5	6,892.1	6,987.0	7,118.6	8,037.1	8,236.1	8,512.9	8,560.3	7,903.8	8,542.1	91,562.1
29	Black Mesa Solar Energy (MWh)	10,402.1	12,164.6	12,320.2	13,249.2	11,406.1	9,606.4	7,799.4	4,147.5	2,532.9	3,525.3	5,560.9	8,951.3	101,665.9
31	Franklin Solar Energy (MWh)	-	-	32,016.5	33,016.7	29,568.5	25,740.0	19,727.6	11,995.9	10,810.5	12,855.5	15,220.6	21,353.9	212,305.8
32	Pleasant Valley Solar Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	38,088.8	38,088.8
33	Total Energy Excl. PURPA (MWh)	106,360.4	89,643.2	170,596.1	449,529.6	462,328.8	283,929.2	244,720.9	418,591.9	565,829.3	504,197.8	195,326.4	174,706.1	3,665,759.6
34	Market Expense ($ x 1000)	$ 240.7	$ 0.5	$ 1,294.2	$ 10,467.4	$ 11,864.4	$ 5,554.0	$ 4,265.3	$ 13,140.0	$ 26,542.7	$ 18,992.7	$ 4,925.5	$ 758.5	$ 98,045.8
35	Elkhorn Wind Expense ($ x 1000)	$ 1,982.5	$ 1,816.9	$ 1,685.2	$ 2,206.6	$ 1,789.5	$ 1,460.2	$ 1,676.0	$ 2,035.3	$ 2,277.5	$ 2,635.1	$ 1,983.8	$ 1,979.1	$ 23,527.8
36	Jackpot Solar Expense ($ x 1000)	$ 608.1	$ 711.2	$ 720.3	$ 774.6	$ 666.8	$ 561.6	$ 456.0	$ 242.5	$ 148.1	$ 206.1	$ 325.1	$ 523.3	$ 5,943.7
37	Neal Hot Springs Expense ($ x 1000)	$ 2,088.2	$ 1,746.0	$ 1,437.2	$ 1,105.5	$ 1,244.5	$ 1,574.3	$ 2,021.2	$ 2,312.3	$ 2,485.4	$ 2,439.8	$ 2,213.4	$ 2,301.4	$ 22,969.2
38	Raft River Geothermal Expense ($ x 1000)	$ 475.4	$ 523.3	$ 469.0	$ 487.0	$ 493.7	$ 503.0	$ 567.9	$ 581.9	$ 601.5	$ 604.9	$ 558.5	$ 603.6	$ 6,469.6
39	Black Mesa Solar Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	Franklin Solar Expense ($ x 1000)	$ -	$ -	$ 936.5	$ 965.7	$ 864.9	$ 752.9	$ 577.0	$ 350.9	$ 316.2	$ 376.0	$ 445.2	$ 624.6	$ 6,209.9
42	Pleasant Valley Solar Expense ($ x 1000)	$ -											$ 249.2	$ 249.2
43	Total Expense Excl. PURPA ($ x 1000)	$ 5,395.0	$ 4,797.8	$ 6,542.4	$ 16,006.8	$ 16,923.8	$ 10,405.9	$ 9,563.4	$ 18,662.8	$ 32,371.4	$ 25,254.6	$ 10,451.5	$ 7,039.7	$ 163,415.1
	Storage													
44	Energy (MWh)	(3,278.05)	(2,924.25)	(4,020.58)	(4,843.53)	(4,808.75)	(4,871.96)	(6,005.05)	(5,432.64)	(5,340.74)	(6,218.93)	(5,995.56)	(6,610.60)	(60,350.6)
45	Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Net Hedges													
46	Energy (MWh)	-	-	16,000.00	70,200.00	23,400.00	-	-	35,168.00	15,416.00	-	-	-	160,184.0
47	Expense ($ X 1000)	$ -	$ -	$ 672.00	$ 5,019.30	$ 1,602.90	$ -	$ -	$ 2,970.72	$ 1,395.15	$ -	$ -	$ -	$ 11,660.1
	Demand Response													
48	Energy (MWh)	-	-	4,917.47	10,748.78	1,542.30	-	-	-	-	-	-	-	17,208.6
49	Expense ($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Oregon Solar													
50	Energy (MWh)	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	36.15	33.52	74.93	811.9
51	Expense ($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Surplus Sales													
52	Energy (MWh)	188,559.9	337,182.3	145,490.2	30,921.1	28,601.3	80,515.2	81,433.5	7,572.9	101.1	138.4	73,266.6	225,615.3	1,199,397.8
53	Revenue ($ x 1000)	$ 4,601.3	$ 7,321.7	$ 5,098.2	$ 1,653.0	$ 1,568.3	$ 4,070.2	$ 3,533.5	$ 421.9	$ 7.8	$ 8.6	$ 4,845.9	$ 9,794.8	$ 42,925.1
54	Surplus Sales - Third Party Transmission Losses ($ x 1000)	$ 483.8	$ 472.6	$ 655.5	$ 996.8	$ 1,047.1	$ 913.6	$ 852.4	$ 1,110.1	$ 1,500.4	$ 1,288.5	$ 1,228.2	$ 907.8	$ 11,457.0
55	Lamb Weston Sales ($ x 1000)	$ 248.1	$ 256.3	$ 301.4	$ 311.5	$ 403.6	$ 283.9	$ 325.8	$ 378.1	$ 390.7	$ 321.2	$ 351.7	$ 389.4	$ 3,961.6
56	Net Power Supply Expenses ($ x 1000)	$ 7,256.5	$ 5,256.5	$ 12,565.7	$ 36,431.7	$ 34,311.2	$ 20,086.9	$ 18,728.4	$ 35,799.6	$ 50,910.8	$ 41,351.9	$ 32,352.8	$ 17,156.1	$ 312,208.2
57	PURPA ($ x 1000)	$ 18,429.4	$ 20,332.6	$ 24,864.6	$ 27,537.1	$ 27,156.9	$ 19,611.2	$ 17,892.5	$ 16,102.6	$ 18,012.9	$ 16,718.1	$ 19,748.8	$ 16,450.4	$ 242,857.0
58	EIM Benefits													$ 48,085.50
59	Total Net Power Supply Expenses ($ x 1000)	$ 25,685.9	$ 25,589.1	$ 37,430.3	$ 63,968.9	$ 61,468.1	$ 39,698.1	$ 36,620.9	$ 51,902.2	$ 68,923.7	$ 58,070.0	$ 52,101.7	$ 33,606.5	**$ 506,979.7**
60	Sales at Customer Level (In 000s MWH)	1,115.435	1,167.634	1,308.382	1,623.897	1,721.080	1,518.048	1,169.715	1,106.011	1,258.720	1,379.529	1,311.532	1,225.844	15,905.826
61	Lamb Weston kWh Sales (In 000s MWH)	4.226	4.367	5.136	5.307	6.877	4.836	5.550	6.441	6.656	5.473	5.992	6.634	67.496
62	Sales at Customer Level - Net Black Mesa Solar & LW (In 000s MWH)	1,100.81	1,151.10	1,290.93	1,605.34	1,702.80	1,503.61	1,156.36	1,095.42	1,249.53	1,370.53	1,299.98	1,210.26	15,736.664
63	Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
64	Unit Cost / MWH (for PCAM)	$23.03	$21.92	$28.61	$39.39	$35.71	$26.15	$31.31	$46.93	$54.76	$42.09	$39.73	$27.42	**$32.22**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 303

Forward Price Curves Used for Re-Pricing Purchased Power and Surplus Sales

March 25, 2024

IDAHO POWER COMPANY
Mid-Columbia Heavy Load and Light Load Daily Forward Curves
Used to Re-Price Purchased Power (PP) and Surplus Sales (SS) for the APCU March Forecast

Line	Mid-Columbia Forward Price Curve on:												
1	**3/13/2024**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**
2	**mc HL**	37.30	27.55	45.05	105.45	157.70	124.15	66.95	72.85	109.05	121.00	95.25	64.25
3	**mc LL**	34.00	17.90	28.00	41.05	59.25	60.85	53.05	57.05	81.85	98.70	79.55	49.45
4	**Reallocated Prices**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**
5	**HL PP**												
6	100.0%	37.30	27.55	45.05	105.45	157.70	124.15	66.95	72.85	109.05	121.00	95.25	64.25
7	**LL PP**												
8	100.0%	34.00	17.90	28.00	41.05	59.25	60.85	53.05	57.05	81.85	98.70	79.55	49.45
9	**HL SS**												
10	100.0%	37.30	27.55	45.05	105.45	157.70	124.15	66.95	72.85	109.05	121.00	95.25	64.25
11	**LL SS**												
12	100.0%	34.00	17.90	28.00	41.05	59.25	60.85	53.05	57.05	81.85	98.70	79.55	49.45

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 304

Total Expected Net Power Supply Expense for the 2024 March Forecast

March 25, 2024

IDAHO POWER COMPANY EXPECTED POWER SUPPLY EXPENSE FOR APRIL 1, 2024 -- MARCH 31, 2025 (One Hydro Condi ion)
2024 APCU March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	728,482 2	952,853.5	828,672.3	598,407.3	517,282.4	487,846.2	414,823.0	366,558.3	422,976.1	472,850.5	497,229.6	653,098.6	6,941,080.0
	Bridger													
2	Energy (MWh)	29,071.2	31,210.8	45,311.1	91,460.9	104,770.7	76,109.4	53,647.0	137,828.4	239,243.3	204,422.4	221,585.2	27,072.1	1,261,732.4
3	Expense ($ x 1000)	$ 1,155.1	$ 1,240.3	$ 1,652.0	$ 3,083.9	$ 3,491.1	$ 2,594.4	$ 1,926.8	$ 4,482.8	$ 7,605.8	$ 6,536.9	$ 7,002.6	$ 1,064.5	$ 41,836.1
	Valmy													
4	Energy (MWh)	157.8	12,231.3	24,581.0	31,232.5	29,105.7	26,080.3	25,054.4	18,583.7	38,583.3	38,714.1	40,706.2	26,356.5	311,386.7
5	Expense ($ x 1000)	$ 360.5	$ 1,011.2	$ 1,676.8	$ 2,038.4	$ 1,922.6	$ 1,757.6	$ 1,702.3	$ 1,353.6	$ 2,457.4	$ 2,460.7	$ 2,573.1	$ 1,774.2	$ 21,088.4
	Bridger Gas													
6	Energy (MWh)	26,225.52	55,464.87	68,750.68	101,488.20	89,906.72	86,093.85	76,846.46	26,088.89	21,210.70	21,966.47	34,024.41	100,069.54	708,136.3
7	Expense ($ x 1000)	$ 785.9	$ 1,567.6	$ 2,119.2	$ 3,769.1	$ 3,716.3	$ 3,173.6	$ 2,709.3	$ 2,368.9	$ 3,698.2	$ 3,718.8	$ 3,733.3	$ 4,806.8	$ 36,167.0
	Langley Gulch													
8	Energy (MWh)	161,767.6	198,626.6	206,711.8	225,267.5	213,849.1	219,370.0	208,238.7	90,668.2	-	23,280.7	117,833.4	183,816.9	1,849,430.3
9	Expense ($ x 1000)	$ 3,114.2	$ 3,043.4	$ 3,673.8	$ 5,408.8	$ 5,740.0	$ 5,234.7	$ 5,334.9	$ 4,986.1	$ -	$ 2,283.7	$ 8,878.3	$ 7,115.1	$ 54,813.0
	Danskin													
10	Energy (MWh)	27,124.4	27,169.1	31,833.2	53,607.9	44,270.7	24,099.6	21,874.6	12,000.1	17,480.4	4,252.3	26,022.1	61,947.7	351,681.9
11	Expense ($ x 1000)	$ 659.7	$ 557.4	$ 803.0	$ 1,892.1	$ 1,782.8	$ 900.6	$ 866.3	$ 1,019.3	$ 2,476.3	$ 616.4	$ 3,108.4	$ 3,688.4	$ 18,370.9
	Bennett Mountain													
12	Energy (MWh)	13,424.9	13,618.2	28,593.2	39,858.2	34,610.2	13,449.9	13,347.3	12,502.2	13,593.7	9,110.7	19,280.0	32,850.7	244,239.2
13	Expense ($ x 1000)	$ 331.2	$ 279.9	$ 693.6	$ 1,365.1	$ 1,341.1	$ 499.5	$ 527.5	$ 1,077.5	$ 1,995.9	$ 1,289.5	$ 2,286.4	$ 1,949.9	$ 13,637.1
14	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 788.1	$ 809.5	$ 788.1	$ 809.5	$ 809.5	$ 788.1	$ 809.5	$ 788.1	$ 809.5	$ 809.5	$ 745.1	$ 809.5	$ 9,564.2
	Purchased Power (Excluding PURPA) & Storage													
15	Market Energy (MWh)	18,915.1	23.5	53,363.8	323,409.7	350,678.2	184,253.1	150,300.6	337,924.9	487,364.2	415,662.7	108,090.9	29,631.8	2,459,618.5
16	Elkhorn Wind Energy (MWh)	26,216.7	24,026.0	22,285.3	29,179.9	23,664.5	19,308.9	22,162.8	26,913.8	30,117.8	34,846.6	26,233.9	26,171.1	311,127.3
17	Jackpot Solar Energy (MWh)	27,457.8	32,110.1	32,520.8	34,973.0	30,108.1	25,357.3	20,587.5	10,947.9	6,685.9	9,305.5	14,678.9	23,628.2	268,361.0
18	Neal Hot Springs Energy (MWh)	16,640.0	13,913.1	11,452.0	8,809.0	9,916.5	12,544.9	16,105.9	18,425.7	19,805.0	19,441.9	17,637.4	18,338.9	183,030.3
19	Raft River Geo hermal Energy (MWh)	6,728.6	7,406.0	6,637.5	6,892.1	6,987.0	7,118.6	8,037.1	8,236.1	8,512.9	8,560.3	7,903.8	8,542.1	91,562.1
20	Black Mesa Solar Energy (MWh)	10,402.1	12,164.6	12,320.2	13,249.2	11,406.1	9,606.4	7,799.4	4,147.5	2,532.9	3,525.3	5,560.9	8,951.3	101,665.9
21	Franklin Solar Energy (MWh)	-	-	32,016.5	33,016.7	29,568.5	25,740.0	19,727.6	11,995.9	10,810.5	12,855.5	15,220.6	21,353.9	212,305.8
22	Pleasant Valley Solar Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	38,088.8	38,088.8
23	Total Energy Excl. PURPA (MWh)	106,360.4	89,643.2	170,596.1	449,529.6	462,328.8	283,929.2	244,720.9	418,591.9	565,829.3	504,197.8	195,326.4	174,706.1	3,665,759.6
24	Market Expense ($ x 1000)	$ 697.9	$ 0.6	$ 2,147.1	$ 24,762.8	$ 38,631.0	$ 17,238.2	$ 8,983.1	$ 21,758.7	$ 47,626.5	$ 45,830.2	$ 9,403.7	$ 1,754.1	$ 218,834.0
25	Elkhorn Wind Expense ($ x 1000)	$ 1,982.5	$ 1,816.9	$ 1,685.2	$ 2,206.6	$ 1,789.5	$ 1,460.2	$ 1,676.0	$ 2,035.3	$ 2,277.5	$ 2,635.1	$ 1,983.8	$ 1,979.1	$ 23,527.8
26	Jackpot Solar Expense ($ x 1000)	$ 608.1	$ 711.2	$ 720.3	$ 774.6	$ 666.8	$ 561.6	$ 456.0	$ 242.5	$ 148.1	$ 206.1	$ 325.1	$ 523.3	$ 5,943.7
27	Neal Hot Springs Expense ($ x 1000)	$ 2,088.2	$ 1,746.0	$ 1,437.2	$ 1,105.5	$ 1,244.5	$ 1,574.3	$ 2,021.2	$ 2,312.3	$ 2,485.4	$ 2,439.8	$ 2,213.4	$ 2,301.4	$ 22,969.2
28	Raft River Geo hermal Expense ($ x 1000)	$ 475.4	$ 523.3	$ 469.0	$ 487.0	$ 493.7	$ 503.0	$ 567.9	$ 581.9	$ 601.5	$ 604.9	$ 558.5	$ 603.6	$ 6,469.6
29	Black Mesa Solar Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Franklin Solar Expense ($ x 1000)	$ -	$ -	$ 936.5	$ 965.7	$ 864.9	$ 752.9	$ 577.0	$ 350.9	$ 316.2	$ 376.0	$ 445.2	$ 624.6	$ 6,209.9
31	Pleasant Valley Solar Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 249.2	$ 249.2
32	Total Expense Excl. PURPA ($ x 1000)	$ 5,852.2	$ 4,797.9	$ 7,395.2	$ 30,302.2	$ 43,690.4	$ 22,090.2	$ 14,281.2	$ 27,281.6	$ 53,455.2	$ 52,092.1	$ 14,929.7	$ 8,035.3	$ 284,203.3
	Storage													
33	Energy (MWh)	(3,278.05)	(2,924.25)	(4,020.58)	(4,843.53)	(4,808.75)	(4,871.96)	(6,005.05)	(5,432.64)	(5,340.74)	(6,218 93)	(5,995.56)	(6,610.60)	(60,350.6)
34	Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Net Hedges													
35	Energy (MWh)	-	-	16,000.00	70,200.00	23,400.00	-	-	35,168.00	15,416.00	-	-	-	160,184.0
36	Cost($ X 1000)	$ -	$ -	$ 672.00	$ 5,019.30	$ 1,602.90	$ -	$ -	$ 2,970.72	$ 1,395.15	$ -	$ -	$ -	$ 11,660.1
	Demand Response													
37	Energy (MWh)	-	-	4,917.47	10,748.78	1,542.30	-	-	-	-	-	-	-	17,208.6
38	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Oregon Solar													
39	Energy (MWh)	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	36.15	33.52	74.93	811.9
40	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Surplus Sales													
41	Energy (MWh)	188,559.9	337,182.3	145,490.2	30,921.1	28,601.3	80,515.2	81,433.5	7,572.9	101.1	138.4	73,266.6	225,615.3	1,199,397.8
42	Revenue ($ x 1000)	$ 6,744.5	$ 7,763.3	$ 5,855.6	$ 2,825.5	$ 4,399.4	$ 9,338.2	$ 5,220.8	$ 550.6	$ 11.0	$ 16.7	$ 6,757.7	$ 13,349.4	$ 62,832.8
43	Surplus Sales - Third Party Transmission Losses ($ x 1000)	$ 483 8	$ 472.6	$ 655.5	$ 996.8	$ 1,047.1	$ 913.6	$ 852.4	$ 1,110.1	$ 1,500.4	$ 1,288.5	$ 1,228.2	$ 907.8	$ 11,457.0
44	Lamb Weston Sales ($ x 1000)	$ 248.1	$ 256.3	$ 301.4	$ 311.5	$ 403.6	$ 283.9	$ 325.8	$ 378.1	$ 390.7	$ 321.2	$ 351.7	$ 389.4	$ 3,961.6
45	Net Power Supply Expenses ($ x 1000)	$ 5,570.5	$ 4,815.0	$ 12,661.2	$ 49,554.6	$ 58,246.7	$ 26,503.1	$ 21,758.8	$ 44,289.7	$ 71,991.4	$ 68,181.3	$ 34,919.3	$ 14,597.1	$ 413,088.7
46	PURPA ($ x 1000)	$ 18,429.4	$ 20,332.6	$ 24,864.6	$ 27,537.1	$ 27,156.9	$ 19,611.2	$ 17,892.5	$ 16,102.6	$ 18,012.9	$ 16,718.1	$ 19,748.8	$ 16,450.4	$ 242,857.0
47	EIM Benefits													$ 48,085.50
48	Total Net Power Supply Expenses ($ x 1000)	$ 23,999.9	$ 25,147.6	$ 37,525.7	$ 77,091.7	$ 85,403.6	$ 46,114.3	$ 39,651.3	$ 60,392.2	$ 90,004.2	$ 84,899.4	$ 54,668.1	$ 31,047.6	**$ 607,860.2**
49	Sales at Customer Level (In 000s MWH)	1,115.435	1,167.634	1,308.382	1,623 897	1,721 080	1,518.048	1,169.715	1,106.011	1,258.720	1,379.529	1,311.532	1,225 844	15,905 826
50	Lamb Weston kWh Sales (In 000s MWH)	4.226	4.367	5.136	5.307	6.877	4.836	5.550	6.441	6.656	5.473	5.992	6.634	67.496
51	Sales at Customer Level - Net Black Mesa Solar & LW (In 000s MWH)	1,100.81	1,151.10	1,290.93	1,605.34	1,702.80	1,503.61	1,156.36	1,095.42	1,249.53	1,370 53	1,299.98	1,210.26	15,736.664
52	Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
53	Unit Cost / MWH (for PCAM)	$21.52	$21.54	$28.68	$47.47	$49.62	$30.38	$33 90	$54.60	$71.50	$61.54	$41.68	$25.33	**$38.63**
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
54	Portion of Purchased Power considered HL Purchases	88%	76%	73%	55%	52%	52%	48%	46%	58%	52%	47%	66%	
55	Purchased Power HL Price	37.30	27.55	45.05	105.45	157.70	124.15	66.95	72.85	109.05	121 00	95.25	64.25	
56	Portion of Surplus Sales considered HL Surplus Sales	54%	53%	72%	78%	96%	87%	80%	99%	100%	100%	81%	66%	
57	Surplus Sales HL Price	37.30	27.55	45.05	105.45	157.70	124.15	66.95	72.85	109.05	121 00	95.25	64.25	
	Light Load													
58	Portion of Purchased Power considered LL Purchases	12%	24%	27%	45%	48%	48%	52%	54%	42%	48%	53%	34%	
59	Purchased Power LL Price	34.00	17.90	28.00	41.05	59.25	60.85	53.05	57.05	81.85	98.70	79.55	49.45	
60	Portion of Surplus Sales considered LL Surplus Sales	46%	47%	28%	22%	4%	13%	20%	1%	0%	0%	19%	34%	
61	Surplus Sales LL Price	34.00	17.90	28.00	41.05	59.25	60.85	53.05	57.05	81.85	98.70	79.55	49.45	

Idaho Power/305
Witness: Jessica G. Brady

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 425

Exhibit 305

Year-Over-Year Differences in March Forecast Net Power Supply Expense

March 25, 2024

IDAHO POWER COMPANY
YEAR OVER YEAR DIFFERENCES IN AURORA DEVELOPED NPSE
2024 March Forecast

	AURORA DEVELOPED NPSE RESULTS BEFORE MARKET ENERGY RE-PRICING			REPRICED USING FORWARD MARKET PRICES					DIFFERENCES			
	GENERATION			GENERATION					GENERATION			
		A	B		C	D	E	F	G	H	I	J
Line No.	Resource Type	2023 March Forecast	2024 March Forecast	Resource Type	2023 March Forecast		2024 March Forecast		(B-A)	(E-C)	(C-A)	(E-B)
1	Hydro (MWh)	6,396,200	6,941,080	Hydro (MWh)	6,396,200	37%	6,941,080	40%	544,880	544,880	-	-
2	Coal (MWh)	1,998,607	1,573,119	Coal (MWh)	1,998,607	12%	1,573,119	9%	(425,488)	(425,488)	-	-
3	Natural Gas (MWh)	1,295,851	3,153,488	Natural Gas (MWh)	1,295,851	8%	3,153,488	18%	1,857,637	1,857,637	-	-
4	Market Purchased Power (MWh)	3,377,535	2,459,619	Market Purchased Power (MWh)	3,377,535	20%	2,459,619	14%	(917,916)	(917,916)	-	-
5	Purchased Power Agreements (MWh)	935,126	1,206,141	Purchased Power Agreements (MWh)	935,126	5%	1,206,141	7%	271,015	271,015	-	-
6	Storage (MWh)	(24,402)	(60,351)	Storage (MWh)	(24,402)	0%	(60,351)	0%	(35,948)	(35,948)	-	-
7	Other*	-	18,020	Other*	-	0%	18,020	0%	18,020	18,020	-	-
8	Net Hedges	635,536	160,184	Net Hedges	635,536	4%	160,184	1%	(475,352)	(475,352)	-	-
9	PURPA (MWh)	2,998,075	2,935,562	PURPA (MWh)	2,998,075	18%	2,935,562	17%	(62,513)	(62,513)	-	-
10	Surplus Sales (MWh)	555,457	1,199,398	Surplus Sales (MWh)	555,457	-3%	1,199,398	-7%	643,941	643,941	-	-
11	System Generation (MWh)	17,612,527	18,386,862	System Generation (MWh)	17,612,527		18,386,862					
12	System Load (MWh)	17,057,070	17,187,465	System Load (MWh)	17,057,070	100%	17,187,465	100%	130,394	130,394	-	-
13	System Load (aMW)	1,947	1,962	System Load (aMW)	1,947		1,962		15	15	-	-

	NET POWER SUPPLY EXPENSES			NET POWER SUPPLY EXPENSES					NET POWER SUPPLY EXPENSES			
		A	B		C	D	E	F	G	H	I	J
	Resource Type	2023 March Forecast	2024 March Forecast	Resource Type	2023 March Forecast		2024 March Forecast		(B-A)	(E-C)	(C-A)	(E-B)
13	Hydro ($ x 1000)	$ -	$ -	Hydro ($ x 1000)	$ -		$ -		$ -	$ -	$ -	$ -
14	Coal ($ x 1000)	$ 72,082.1	$ 62,924.5	Coal ($ x 1000)	$ 72,082.1	10%	$ 62,924.5	10%	$ (9,157.5)	$ (9,157.5)	$ -	$ -
15	Natural Gas ($ x 1000)	$ 43,596.5	$ 132,552.2	Natural Gas ($ x 1000)	$ 43,596.5	6%	$ 132,552.2	22%	$ 88,955.6	$ 88,955.6	$ -	$ -
16	Market Purchased Power ($ x 1000)	$ 101,029.7	$ 98,045.8	Market Purchased Power ($ x 1000)	$ 384,086.0	51%	$ 218,834.0	36%	$ (2,983.9)	$ (165,252.0)	$ 283,056.3	$ 120,788.19
17	Purchased Power Agreements ($ x 1000)	$ 53,853.0	$ 65,369.3	Purchased Power Agreements ($ x 1000)	$ 53,853.0	7%	$ 65,369.3	11%	$ 11,516.3	$ 11,516.3	$ -	$ -
18	Storage ($ x 1000)	$ -	$ -	Storage ($ x 1000)	$ -	0%	$ -	0%	$ -	$ -	$ -	$ -
19	Net Hedges	$ 46,387.5	$ 11,660.1		$ 46,387.5	6%	$ 11,660.1	2%		$ (34,727.5)		
20	PURPA ($ x 1000)	$ 233,010.9	$ 242,857.0	PURPA ($ x 1000)	$ 233,010.9	31%	$ 242,857.0	40%	$ 9,846.2	$ 9,846.2	$ -	$ -
21	Surplus Sales ($ x 1000)	$ (17,461.5)	$ (58,343.7)	Surplus Sales ($ x 1000)	$ (41,762.4)	-6%	$ (78,251.4)	-13%	$ (40,882.1)	$ (36,489.0)	$ (24,300.9)	$ (19,907.72)
22	EIM Benefits	$ (34,739.0)	$ (48,085.5)	EIM Benefits	$ (34,739.0)	-5%	$ (48,085.5)	-8%	$ (13,346.5)	$ (13,346.5)	$ -	$ -
23	Total System ($ x 1000)	$ 497,759.2	$ 506,979.7	Total System ($ x 1000)	$ 756,514.6	100%	$ 607,860.2	100%	$ 9,220.5	$ (148,654.4)	$ 258,755.4	$ 100,880.5

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 306

Energy Imbalance Market Benefit

March 25, 2024

IDAHO POWER COMPANY
2024 APCU March Forecast
Energy Imbalance Market Benefit Forecast
Based on February 2023-January 2024 Historical Data

		(A)	(B)	(C)	(F)
Year	**Month**	**CAISO Benefit**	**Zero-cost Hydro Adjustment**	**Hydro Net (Export)/Import Adjustment**	**Idaho Power EIM Benefit**
2023	February	$ 3,332,363	$ 1,235,784	$ 778,353	$ 2,014,137
2023	March	$ 3,674,335	$ 2,800,432	$ (9,341)	$ 2,791,091
2023	April	$ 8,429,942	$ 9,549,223	$ (155,659)	$ 9,393,563
2023	May	$ 17,861,967	$ 17,106,028	$ 6,612	$ 17,112,640
2023	June	$ 5,232,257	$ 4,020,478	$ (73,071)	$ 3,947,408
2023	July	$ 3,453,712	$ 2,255,875	$ (702,437)	$ 1,553,438
2023	August	$ 3,024,493	$ 1,402,323	$ (54,594)	$ 1,347,730
2023	September	$ 2,149,343	$ 1,675,130	$ (301,780)	$ 1,373,350
2023	October	$ 4,267,170	$ 2,515,778	$ (539,694)	$ 1,976,084
2023	November	$ 3,397,213	$ 2,114,869	$ 20,492	$ 2,135,360
2023	December	$ 1,801,242	$ 309,091	$ 334,708	$ 643,799
2024	January	$ 7,650,267	$ 6,644,252	$ (2,847,348)	$ 3,796,904
Total		**$ 64,274,305**	**$ 51,629,263**	**$ (3,543,760)**	**$ 48,085,503**

Idaho Power/307
Witness: Jessica G. Brady

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 307

Energy Imbalance Market Costs

March 25, 2024

Idaho Power Company
2024 APCU
EIM Costs & Benefits

2023 Calendar Year Revenue Requirement

Capital Investment	$368,373
ADIT	($11,114)
Accumulated Depreciation	($12,810)
Amortization of Other Plant	($209,621)
Net Rate Base	$134,829
Return on Rate Base	**$10,459**
O&M (On-going)	$85,492
Depreciation	$20,720
Taxes	($27,974)
Total Operating Expenses	**$78,238**
Net-to-Gross Tax Multiplier	1.347
Total Annual Revenue Requirement	$119,441
Total Rev Req (4/1/24 - 10/14/24)	**$64,289**

EIM Benefits

Oregon Allocated EIM Benefits	**($64,289)**

Impact to NPSE	**$0**

Idaho Power/308
Witness: Jessica G. Brady

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 308

October Update and March Forecast Combined Rate Calculation

March 25, 2024

Idaho Power Company
2024 APCU Combined Rate Calculation
April 2024 - March 2025

Line	OCTOBER UPDATE	
1	Forecast of Normalized Sales (MWh)	15,739,816
2	Total Net Power Supply Expense	$484,523,606
3	October APCU Unit Cost ($/MWh)	$30.78
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	15,736,664
5	Total Net Power Supply Expense	$607,860,187
6	March Forecast Unit Cost ($/MWh)	$38.63
7	Sales Adjusted Forecast Power Cost Change	$123,532,811
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$117,356,171
10	**March Forecast Rate ($/MWh)**	$7.46
11	**Combined Rate ($/MWh)**	$38.24

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 309

Stipulated Revenue Spread and Revenue Impact

March 25, 2024

Idaho Power Company
Stipulated Revenue Spread
2024 APCU October Update

Line No.		
1	2023 October Update Oregon Jurisdictional Share of Base NPSE = $30.78/MWh x 656,167.451 MWhs =	$ 20,196,834
2	**Oregon Allocated EIM Costs***	**$ 64,289**
3	**Proposed October Update APCU Revenue Requirement**	**$ 20,261,123**

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 2022 - March 2023 Generation Level Normalized Sales (kWh)**	**696,529,652**	208,505,679	130,124	20,564,278	118,310,551	22,022,758	3,140,157	235,793	155,691,934	97,785,417	69,701,496	5,787	412,852	22,827
5	**Class Share of April 2022 - March 2023 Generation Level Normalized Sales (kWh)**	**100%**	29.93%	0.02%	2.95%	16.99%	3.16%	0.45%	0.03%	22.35%	14.04%	10.01%	0.00%	0.06%	0.00%
6	**2021 October Update Class Allocated Base NPSE**	**$ 20,261,123**	$ 6,065,154	$ 3,785	$ 598,188	$ 3,441,497	$ 640,613	$ 91,343	$ 6,859	$ 4,528,872	$ 2,844,448	$ 2,027,524	$ 168	$ 12,009	$ 664
7	**June 2022 - May 2023 Loss-Adjusted Normalized Sales (kWh)**	**656,419,089**	194,241,834	121,119	19,151,261	110,181,444	20,956,450	3,051,659	219,547	148,156,195	95,029,560	64,898,972	5,388	384,406	21,254
8	**Proposed APCU Rates for 2024 October Update ($/kWh)**	**0.030866**	0.031225	0.031251	0.031235	0.031235	0.030569	0.029932	0.031241	0.030568	0.029932	0.031241	0.031241	0.031241	0.031241
9	**Proposed October Update APCU Revenue Requirement**	**$ 20,261,123**	$ 6,065,154	$ 3,785	$ 598,188	$ 3,441,497	$ 640,613	$ 91,343	$ 6,859	$ 4,528,872	$ 2,844,448	$ 2,027,524	$ 168	$ 12,009	$ 664
10	**APCU Rates for 2023 October Update ($/kWh) - Order No. 23-184**	**0.030889**	0.031490	0.031490	0.031451	0.031449	0.030454	0.029708	0.031490	0.030420	0.029651	0.031449	0.031483	0.031490	0.031488
11	**June 2022 - May 2023 Loss-Adjusted Normalized Sales (kWh)**	**656,419,089**	194,241,834	121,119	19,151,261	110,181,444	20,956,450	3,051,659	219,547	148,156,195	95,029,560	64,898,972	5,388	384,406	21,254
12	**Base NPSE Recovered under Current APCU Rates**	**$ 20,302,329**	$ 6,116,632	$ 3,814	$ 602,333	$ 3,465,106	$ 638,204	$ 90,660	$ 6,914	$ 4,506,972	$ 2,817,729	$ 2,041,023	$ 170	$ 12,105	$ 669

Idaho Power Company
Stipulated Revenue Spread
2024 APCU March Forecast

Line No.		
1	Oregon Jurisdictional Share of 2024 March Forecast NPSE = $7.46/MWh x 656,167.451 MWhs =	$ 4,895,009

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 2024 - March 2025Generation Level Normalized Sales (kWh)	696,529,652	208,505,679	130,124	20,564,278	118,310,551	22,022,758	3,140,157	235,793	155,691,934	97,785,417	69,701,496	5,787	412,852	22,827
3	Class Share of April 2024 - March 2025 Generation Level Normalized Sales (kWh)	100%	29.93%	0.02%	2.95%	16.99%	3.16%	0.45%	0.03%	22.35%	14.04%	10.01%	0.00%	0.06%	0.00%
4	2023 March Forecast Class Allocated NPSE	$ 4,895,009	$ 1,465,318	$ 914	$ 144,520	$ 831,452	$ 154,770	$ 22,068	$ 1,657	$ 1,094,158	$ 687,208	$ 489,842	$ 41	$ 2,901	$ 160
5	June 2024 - May 2025 Loss-Adjusted Normalized Sales (kWh)	656,419,089	194,241,834	121,119	19,151,261	110,181,444	20,956,450	3,051,659	219,547	148,156,195	95,029,560	64,898,972	5,388	384,406	21,254
6	Proposed APCU Rates for 2023 March Forecast ($/kWh)	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
7	Proposed March Forecast Revenue Requirement	$ 4,895,009	$ 1,465,318	$ 914	$ 144,520	$ 831,452	$ 154,770	$ 22,068	$ 1,657	$ 1,094,158	$ 687,208	$ 489,842	$ 41	$ 2,901	$ 160
8	Current APCU Rates for 2023 March Forecast ($/kWh) - Order No. 23-184	0.016641	0.016965	0.016965	0.016944	0.016943	0.016407	0.016005	0.016965	0.016389	0.015974	0.016943	0.016961	0.016965	0.016964
9	June 2024 - May 2025 Loss-Adjusted Normalized Sales (kWh)	656,419,089	194,241,834	121,119	19,151,261	110,181,444	20,956,450	3,051,659	219,547	148,156,195	95,029,560	64,898,972	5,388	384,406	21,254
10	NPSE Recovered under Current March Forecast Rates	$ 10,937,563	$ 3,295,240	$ 2,055	$ 324,498	$ 1,866,772	$ 343,822	$ 48,842	$ 3,725	$ 2,428,061	$ 1,518,007	$ 1,099,569	$ 91	$ 6,521	$ 361

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2024

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	2024 October Update Proposed Base NPSE Revenue	Total Proposed Base Revenue	2024 October Update Proposed Adjustments to Base Revenue	2024 October Update Base Revenue Percent Change	Current Billed Revenue w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	2024 March Forecast Proposed Revenue	2024 March Forecast Proposed Adjustments to Billed Revenue	2024 March Forecast Revenue Percent Change	2024 Composite APCU Revenue Adjustment	Proposed Total Billed Revenue	2024 Composite APCU Percent Change
	Uniform Tariff Rates:																			
1	Residential Service	1	13,812	194,241,834	$ 12,574,204	$ 6,116,632	$ 18,690,835	$ 6,065,154	$ 18,639,357	$ (51,478)	(0.28)%	$ 19,150,507	$ 3,295,240	$ 22,445,747	$ 1,465,318	$ (1,829,922)	(8.15)%	$ (1,881,400)	$ 20,564,346	(8.38)%
2	Residential Service - Time-of-Day Pilot	5	4	121,119	$ 7,451	$ 3,814	$ 11,265	$ 3,785	$ 11,236	$ (29)	(0.26)%	$ 11,551	$ 2,055	$ 13,606	$ 914	$ (1,140)	(8.38)%	$ (1,169)	$ 12,437	(8.59)%
3	Small General Service	7	2,745	19,151,261	$ 1,472,172	$ 602,333	$ 2,074,506	$ 598,188	$ 2,070,360	$ (4,146)	(0.20)%	$ 2,112,234	$ 324,498	$ 2,436,732	$ 144,520	$ (179,978)	(7.39)%	$ (184,123)	$ 2,252,608	(7.56)%
4	Large General Secondary	9S	960	110,181,444	$ 5,476,157	$ 3,465,106	$ 8,941,262	$ 3,441,497	$ 8,917,653	$ (23,609)	(0.26)%	$ 9,151,579	$ 1,866,772	$ 11,018,350	$ 831,452	$ (1,035,319)	(9.40)%	$ (1,058,928)	$ 9,959,422	(9.61)%
5	Large General Primary	9P	9	20,956,450	$ 894,543	$ 638,204	$ 1,532,747	$ 640,613	$ 1,535,156	$ 2,409	0.16%	$ 1,572,425	$ 343,822	$ 1,916,247	$ 154,770	$ (189,053)	(9.87)%	$ (186,644)	$ 1,729,603	(9.74)%
6	Large General Transmission	9T	1	3,051,659	$ 108,176	$ 90,660	$ 198,836	$ 91,343	$ 199,519	$ 683	0.34%	$ 204,555	$ 48,842	$ 253,397	$ 22,068	$ (26,773)	(10.57)%	$ (26,090)	$ 227,306	(10.30)%
7	Dusk to Dawn Lighting	15	0	219,547	$ 102,205	$ 6,914	$ 109,118	$ 6,859	$ 109,064	$ (55)	(0.05)%	$ 109,623	$ 3,725	$ 113,348	$ 1,657	$ (2,067)	(1.82)%	$ (2,122)	$ 111,226	(1.87)%
8	Large Power Primary	19P	5	148,156,195	$ 4,949,395	$ 4,506,972	$ 9,456,367	$ 4,528,872	$ 9,478,266	$ 21,900	0.23%	$ 9,734,042	$ 2,428,061	$ 12,162,103	$ 1,094,158	$ (1,333,903)	(10.97)%	$ (1,312,003)	$ 10,850,099	(10.79)%
9	Large Power Transmission	19T	1	95,029,560	$ 3,325,000	$ 2,817,729	$ 6,142,728	$ 2,844,448	$ 6,169,448	$ 26,719	0.43%	$ 6,320,830	$ 1,518,007	$ 7,838,837	$ 687,208	$ (830,800)	(10.60)%	$ (804,080)	$ 7,034,757	(10.26)%
10	Agricultural Irrigation Service	24	2,309	64,898,972	$ 4,577,952	$ 2,041,023	$ 6,618,975	$ 2,027,524	$ 6,605,476	$ (13,498)	(0.20)%	$ 6,746,087	$ 1,099,569	$ 7,845,656	$ 489,842	$ (609,727)	(7.77)%	$ (623,226)	$ 7,222,430	(7.94)%
11	Unmetered General Service	40	2	5,388	$ 186	$ 170	$ 356	$ 168	$ 355	$ (1)	(0.37)%	$ 366	$ 91	$ 458	$ 41	$ (51)	(11.08)%	$ (52)	$ 406	(11.37)%
12	Street Lighting	41	27	384,406	$ 134,347	$ 12,105	$ 146,452	$ 12,009	$ 146,356	$ (96)	(0.07)%	$ 147,285	$ 6,521	$ 153,806	$ 2,901	$ (3,620)	(2.35)%	$ (3,715)	$ 150,091	(2.42)%
13	Traffic Control Lighting	42	11	21,254	$ 1,520	$ 669	$ 2,189	$ 664	$ 2,184	$ (5)	(0.24)%	$ 2,231	$ 361	$ 2,591	$ 160	$ (200)	(7.72)%	$ (205)	$ 2,386	(7.93)%
14	Total Uniform Tariffs		19,886	656,419,089	$ 33,623,307	$ 20,302,329	$ 53,925,636	$ 20,261,123	$ 53,884,431	$ (41,206)	(0.08)%	$ 55,263,313	$ 10,937,563	$ 66,200,877	$ 4,895,009	$ (6,042,554)	(9.13)%	$ (6,083,760)	$ 60,117,117	(9.19)%
15	Total Oregon Retail Sales		19,886	656,419,089	$ 33,623,307	$ 20,302,329	$ 53,925,636	$ 20,261,123	$ 53,884,431	$ (41,206)	(0.08)%	$ 55,263,313	$ 10,937,563	$ 66,200,877	$ 4,895,009	$ (6,042,554)		$ (6,083,760)	$ 60,117,117	(9.19)%

(1) Updated June 2024-May 2025 Test Year