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October 31, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Filing Center
P.O. Box 1088
201 High Street S.E., Suite 100
Salem, OR 97308-1088

Re: Docket UE 425 – Idaho Power Company's 2024 Annual Power Cost Upgrade (APCU)

Attention Filing Center:

Attached for filing in the above-referenced docket is Idaho Power Company's Direct Testimony of Jessica G. Brady and Exhibits of Jessica G. Brady (Idaho Power/100-110). Please direct all communications in this matter to the following individuals:

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An electronic copy of this filing has been served on all parties in Docket UE 414 - In the Matter of IDAHO POWER COMPANY, 2023 Annual Power Cost Update.

Please contact this office with any questions.

Sincerely,

/s/ Cole Albee

Cole Albee
Paralegal

Attachments:
Cc: UE 414 Service List

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

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

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JESSICA G. BRADY

October 31, 2023

Q. Please state your name, business address, and present occupation.

A. My name is Jessica G. Brady. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Regulatory Analyst in the Regulatory Affairs Department. My business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. Please describe your educational background.

A. In May 2016, I received a Bachelor of Science degree in Economics and a Bachelor of Arts degree in Spanish from the University of Idaho. I have also attended "The Basics: Practical Regulatory Training for the Electric Industry," an electric utility ratemaking course offered through New Mexico State University's Center for Public Utilities, "Electric Utility Fundamentals & Insights," an electric utility course offered through the Western Energy Institute, and Edison Electric Institute's "Electric Rates Course" offered at the University of Wisconsin-Madison.

Q. Please describe your business experience.

A. In September 2021, I accepted my current position at Idaho Power as a Regulatory Analyst in the Regulatory Affairs Department. As a Regulatory Analyst, I am responsible for running the AURORA model ("AURORA") to calculate net power supply expenses ("NPSE") for ratemaking purposes, as well as the determination of the marginal cost of energy used in the Company's marginal cost analyses. My duties also include providing analytical support for other regulatory activities within the Regulatory Affairs Department.

Prior to Idaho Power, I worked for five years at Clearwater Analytics, a provider of investment accounting and reporting software. I held various roles at Clearwater but was primarily focused on customer success and relationship management. I gained a breadth of knowledge in investments and the use of proprietary software to streamline the operations of a company's finance and accounting teams. I spent my last year at

Clearwater developing a training program focused on providing new hires with the technical skills to be successful in an operations role.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the determination of the Company's 2024 October Update, the first portion of the Company's Annual Power Cost Update ("APCU"). If approved, the 2024 October Update will result in a revenue decrease of $101,556, or a 0.18 percent decrease in base revenue collection, to become effective June 1, 2024.

Q. How is your testimony organized?

A. My testimony begins with a brief history of the APCU, and the filing requirements associated with it. Next, my testimony describes the required updates to AURORA and the resulting modeling outputs. I then present and discuss the total NPSE for the 2024 October Update, and how it compares to last year's 2023 October Update. My testimony then discusses the quantification of the projected revenue requirement and the proposed rate implementation to recover the revenue requirement.

Q. Have you prepared exhibits for this proceeding?

A. Yes. I am sponsoring the following exhibits:

1. Exhibit 101, AURORA modeled determination of normalized power supply expenses for April 1, 2024 – March 31, 2025
2. Exhibits 102 – 104, Mid-Columbia Forward Price Curves Discounted for Inflation, Producer Price Index for Electric Power, and Forward Prices Used for Re-Pricing Purchased Power and Surplus Sales
3. Exhibit 105, Total Normalized Base Power Supply Expenses for the 2024 October Update
4. Exhibit 106, Energy Imbalance Market Benefits
5. Exhibit 107, Energy Imbalance Market Costs

6. Exhibit 108, Year-Over-Year Differences in Modeled NPSE
7. Exhibits 109 – 110, Revenue Spread and Revenue Impact

APCU Overview

Q. What is the APCU?

A. The APCU is a rate mechanism that has two components, an October Update and a March Forecast. The October Update establishes the prospective "base" or "normal" power supply expenses for an April through March test period. The March Forecast is a forecast of expected power supply expenses over the same test period as the October Update. "Base" or "normal" power supply expenses are calculated by modeling the test period under multiple historical water conditions; in this case, the Company modeled 37 historical water conditions (1981-2017) as discussed later in my testimony. Expected power supply expenses are calculated by modeling the same test period as the October Update, except the power supply expenses are calculated by modeling a single forecast water condition. The results of the October Update are reflected as an update to base rates and the results of the March Forecast are reflected in the March Forecast Rate Adjustment listed in Schedule 55, with both of the rate adjustments going into effect on June 1st of each year.

Q. What is the definition of the term "net power supply expense" as the Company and the Public Utility Commission of Oregon ("Commission") have used the term historically?

A. The Company and the Commission have used the term "net power supply expense" to refer to the sum of the following Federal Energy Regulatory Commission ("FERC") accounts: fuel expense (FERC Accounts 501 and 547), and purchased power expenses (FERC Account 555), minus surplus sales revenues (FERC Account 447).

Q. What regulatory actions led to the implementation of the APCU?

A. In the final order issued in Idaho Power's general rate case, docket UE 167, the Commission specifically recognized the Company's unique reliance on hydro generation and its extended amortization of deferred costs, and therefore, directed the parties to work together to "consider whether there is a more effective regulatory mechanism for Idaho Power to recover its allowable power costs."[1] Following that order, the Company filed its request for a power cost adjustment mechanism ("PCAM"). The result of that filing was a settlement stipulation approved by the Commission in Order No. 08-238[2], establishing the APCU and implementation of the PCAM, or the annual power supply expense true-up.

Q. What is the purpose of the APCU?

A. The APCU was implemented to adjust rates on an annual basis to capture variability in power supply expenses that occur with a predominantly hydro-based generation fleet. The APCU mechanism closely aligns the power supply expenses included in customer rates with the power supply expenses actually incurred by the Company. Prior to the APCU, the Company would defer excess power supply expenses and then amortize them at a later time for collection, which led to multiple deferrals and long amortization periods.

Q. What are the general requirements for the APCU described in Order No. 08-238?

A. Order No. 08-238 directed the Company to model its power supply expenses using the AURORA model and identified a number of variables that were to be updated annually in AURORA. The specific variables are discussed in the following section.

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[1] *In the Matter of Idaho Power Company Application for General Rate Increase in the Company's Oregon Annual Revenues*, Docket No. UE 167, Order No. 05-871 at 7 (July 28, 2005).

[2] *In the Matter of Idaho Power Company Application for Authority to Implement a Power cost Adjustment Mechanism for Electric Service Customers in the State of Oregon*, Docket No. UE 195, Order No. 08-238 (April 28, 2008).

Q. What is the AURORA model?

A. The AURORA model is a comprehensive electric resource dispatch model that simulates the economic dispatch of the Company's resources to determine NPSE for the APCU. The Commission has also accepted the use of AURORA to determine NPSE for general rate cases, marginal cost analyses, and resource modeling for the Company's Integrated Resource Plan ("IRP").

AURORA Model Inputs and Modeling Results

Q. What are the specific variables that are updated during each APCU filing?

A. Commission Order No. 08-238 identified the following power supply expense variables to be updated annually:

a. Fuel prices and transportation costs
b. Wheeling expenses
c. Planned outages and forced outage rates
d. Heat rates
e. Forecast of normalized load and normalized sales
f. Contracts for wholesale power and power purchases and sales
g. Forward price curve
h. Public Utility Regulatory Policies Act of 1978 ("PURPA") contract expenses
i. The Oregon state allocation factor

The Company reviewed all the inputs and updated those that have changed since last year's October Update, as described in more detail in the following sections.

Coal Fuel Expense

Q. Have any changes in coal fuel expense and coal-fired generation occurred since last year's October Update filing?

A. Yes. Total coal fuel expense included in the 2024 October Update is $84.6 million, compared to $82.1 million in the 2023 October Update, an increase of 3 percent. Coal-fired generation decreased from last year's October Update, from 2.46 million megawatt-hours ("MWh") to 2.08 million MWh, a decrease of 15 percent.

Q. What is driving the decrease in year-over-year coal-fired generation?

A. Forecast coal-fired generation decreased 15 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 summer 2024, and as a result, were modeled as natural gas resources for this test year. This is discussed in more detail later in my testimony.

Q. How did the changes in coal fuel expense and coal-fired generation impact the cost of coal production on a per-unit basis?

A. The average per-unit cost of coal production for the 2024 October Update is $40.63 per MWh, compared to $33.41 per MWh for the 2023 October Update. At Bridger, the per-unit cost of production increased 11 percent, from $32.15 per MWh in 2023 to $35.59 per MWh in this year's October Update. This is primarily due to increases in both the modeled heat rate and coal prices at Bridger.

The per-unit cost of production at Valmy decreased in this year's October Update compared to last year. This is primarily a result of fixed costs being spread over increased generation (from 90 MWhs to approximately 468,013 MWh) as well as a 31 percent decrease in forecast coal prices at Valmy.

Q. Did Idaho Power model Oil, Handling, and Administrative and General ("OHAG") expenses as agreed upon in the settlement stipulations approved in the 2016 and 2017 APCU dockets?

A. Yes. Per the settlement stipulation approved in the 2016 APCU[3], the per-MWh OHAG expense included in the AURORA model has been updated to reflect the amount of OHAG expense driven by Idaho Power's dispatch of the Bridger and Valmy plants. The Company has separately accounted for its proportional share of the total OHAG expense incurred at both plants. Per the settlement stipulation approved in the Company's 2017 APCU[4], Idaho Power's proportional share of total OHAG expense incurred at both of the coal-fired plants is forecast using a three-year historical average of actual OHAG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate.

Q. Have you prepared an exhibit that illustrates the calculation of OHAG expenses for the 2024 APCU?

A. Yes. Exhibit 101 reflects the AURORA-modeled OHAG expense resulting from Idaho Power's dispatch, as well as Idaho Power's fixed ownership share of total OHAG expense at both of its coal-fired plants. This methodology effectively includes in the AURORA dispatch price the true variable component of OHAG driven by the Company's dispatch of each plant. After the AURORA-modeled dispatch has occurred, the resulting costs are adjusted to align with costs actually incurred by the Company at both of its coal-fired facilities.

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[3] *In the Matter of Idaho Power Company's 2016 Annual Power Cost Update*, Docket No. UE 301, Order No. 16-206 (May 31, 2016).

[4] *In the Matter of Idaho Power Company's 2017 Annual Power Cost Update*, Docket No. UE 314. Order No. 17-165. (May 16, 2017).

For example, on Exhibit 101, Line 4 illustrates the AURORA-modeled OHAG expense resulting from Idaho Power's dispatch of Bridger. Line 5 is the difference between the total AURORA-modeled expenses, Line 3, and the AURORA-modeled OHAG expense, Line 4, at Bridger ($59,734.7 + $613.7 = $60,348.4). Line 6 represents the Company's proportional share of total OHAG expenses at Bridger using the stipulated methodology discussed above. Line 7 is the sum of the AURORA-modeled expenses (less the AURORA-modeled OHAG at Bridger, Line 5), and the Company's proportional share of total OHAG, Line 6, ($60,348.4 - $2,863.8 = $57,484.5). Line 7 reflects the final total NPSE for Bridger. In this case, calculated OHAG at Bridger reduces total expenses due to proceeds from the sale of combustion fly ash. This method is replicated for Valmy as shown on Lines 9-14.

Q. Does Idaho Power's 2024 APCU account for revenues received from or expenses paid to NV Energy (its ownership partner in Valmy) for usage of the Company's unused capacity or the Company's usage of NV Energy's unused capacity?

A. Yes. Per the settlement stipulation approved in the 2017 APCU,[5] Idaho Power agreed to include the three-year historical average of actual net balances associated with ownership partner use of unused capacity at Valmy as an offset or addition to total NPSE.

For the 2024 October Update, the 2020-2022 historical average net revenue paid to Idaho Power associated with NV Energy's dispatch of Idaho Power's unused capacity at Valmy is $71,106 on a system basis. As shown on Line 13 of Exhibit 101, this amount has been reflected as an offset to NPSE for Valmy for the 2024 October

[5] *Id* at 4.

Update. The Company will update the three-year historical average as part of the 2024 March Forecast.

Natural Gas Fuel Expense

Q. Have any changes in natural gas expense and generation occurred since last year's October Update filing?

A. Yes. Natural gas expense in this year's October Update is $163.4 million, compared to $53.3 million in 2023, an increase of 206 percent. Natural gas generation in this year's October Update is 3.03 million MWh compared to 1.13 million MWh in 2023, an increase of 170 percent.

Q. Please explain the increase in natural gas generation in this year's October Update.

A. The 170 percent increase in natural gas generation can be attributed to the increase in capacity related to the conversion of Bridger units 1 and 2 to natural gas, as well as the increase in opportunity to make off-system economic sales. The average AURORA-calculated market price associated with surplus sales in this year's October Update is $43.29, compared to $35.56 last year, an increase of 22 percent.

Q. How does the natural gas price forecast for the 2024 October Update compare to last year's October Update?

A. The Henry Hub price used for the 2023 October Update was $5.84 per MMBtu, while the Henry Hub price used in the 2024 October Update is $3.90 per MMBtu, a decrease of $1.94 per MMBtu or 33 percent.

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 $3.90 per MMBtu applied to a

Sumas basis of $1.54 per MMBtu equals a Sumas gas price of $5.44 per MMBtu ($3.90 + $1.54 = $5.44). The Company develops a separate gas price for its natural gas units also based upon the Henry Hub gas price forecast.

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 October Update compare to last year?

A. The average Idaho Citygate price for the 2024 October Update is $5.21 per MMBtu compared to $5.63 per MMBtu for the 2023 October Update.

Q. What is driving the decrease in the Idaho Citygate price?

A. The decrease in the Idaho Citygate price for the 2024 October Update 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. According to the U.S. Energy Information Administration ("EIA"), record high levels of U.S. natural gas production have resulted in natural gas inventories well above the 5-year average in 2023.[6]

Q. What is the Bridger Gas price used in this year's October Update?

A. The average Bridger Gas price for the 2024 October Update is $4.43 per MMBtu.

[6] https://www.eia.gov/todayinenergy/detail.php?id=57200

PURPA Expense

Q. Please explain any changes in PURPA generation since last year's October Update.

A. Last year's October Update included 362.0 average megawatts ("aMW") of PURPA generation, whereas PURPA generation included in the 2024 October Update is 354.7 aMW, a decrease of 7.35 aMW, or 2.03 percent. The decrease in PURPA generation is primarily due to normal fluctuations in estimated output from the Company's existing PURPA-contracted facilities.

Q. How has the annual PURPA expense changed from last year's October Update?

A. Forecast PURPA expense in this year's October Update is $250.3 million, an increase of $3.0 million, or 1 percent, compared to last year's forecast. Compared to last year's settled PURPA expense amount, this year's PURPA forecast is an increase of $10.1 million, or 4 percent. The increase in forecast annual PURPA expense is primarily a result of updated PURPA contract values, partially offset by decreased forecast generation.

New Resources

Q. Have any additional resources been added to the Company's resource portfolio since last year's 2023 October Update?

A. Yes. The following resources have been added to the AURORA model for this year's October Update. In order to calculate a "base" or "normal" level of net power supply expense, all new resources were modeled as annualized online resources for the entire test year, reflecting the same treatment applied to new projects in prior APCU dockets when they were scheduled to come online during an APCU test year.

a. Bridger Gas
b. Franklin Solar
c. Franklin Battery Energy Storage System ("BESS")

d. 36 Megawatt ("MW") Hemingway BESS

e. Pleasant Valley Solar

Q. Please describe the new resources, including how they were modeled for the October 2024 filing.

A. The Bridger Gas resource represents Bridger units 1 and 2 converted to natural gas. As listed in the Company's 2021 and 2023 IRP Action Plans, Bridger units 1 and 2 will be converted to natural gas by summer 2024. As a result, they were modeled as natural gas resources for the 2024 APCU test year.

Franklin Solar is a 100-MW alternating current solar photovoltaic facility that is scheduled to come online June 2024. It is a 25-year Power Purchase Agreement ("PPA") with Franklin Solar, LLC. Franklin BESS, co-located with Franklin Solar, is a Build Transfer Agreement ("BTA") with Duke Energy Renewables Solar LLC, providing for a minimum capacity of 60 MW.

The 36-MW Hemingway BESS resource represents the addition of 36 MW of Idaho Power-owned battery storage at the Hemingway substation. Both the Franklin BESS and 36-MW Hemingway BESS were modeled so that the scheduled generation of each battery is shaped to the Company's demand, net of the "must-run" PURPA and PPA resources. In addition, both were modeled to be grid-charged.

Pleasant Valley Solar is a 200-MW alternating current solar photovoltaic facility that is scheduled to come online March 2025. It is a PPA that was negotiated in conjunction with a new special contract[7] with Brisbie, LLC ("Brisbie"). Meta Platforms, Inc. is the parent company of Brisbie. Brisbie's special contract states that Idaho Power will procure renewable resources to support 100 percent of Brisbie's operations with

[7] A "special contract"—i.e., an individualized tariff schedule—is required for customers with an aggregate power requirement greater than 20 MW in both the Company's Idaho and Oregon jurisdictions.

renewable energy on an annual basis. Pleasant Valley Solar will be connected to the Company's system and will not serve Brisbie directly. However, Brisbie will pay for the full cost of the PPA, as well as Idaho Power retail electric service required to support their load. In addition, Brisbie will receive the value that the Pleasant Valley resource provides Idaho Power's system and will be credited for any PPA generation that exceeds their load in a given hour. Because the Pleasant Valley resource comes online prior to Brisbie's load in December 2025, the expenses associated with Pleasant Valley Solar in this APCU test year represent the excess generation from the PPA, as well as the capacity contribution. Per the terms of the contract, the value of excess generation is defined as the lower of 1) 85 percent of a non-firm Mid-Columbia hourly price forecast, or 2) actual heavy-load, light-load price in the hour of excess generation. Because actual heavy-load, light-load prices are not known for a forecast period, the Company used Pleasant Valley generation-shaped-weighted average monthly non-firm Mid-C market prices from the Company's 2023 IRP as an estimate.

Normalized Load

Q. Please describe the changes in the Company's system loads since last year's October Update.

A. The Company's normalized system load used in last year's October Update was 1,957 aMW. The Company's normalized system load used in this year's October Update is 1,971 aMW, representing an increase in load of 14 aMW, or 0.7 percent, between the two test years.

Q. Please explain what is driving the increase in the Company's system load.

A. The 0.7 percent increase in system load is primarily due to the inclusion of third-party transmission losses into the Company's load forecast. Third-party transmission losses represent the additional electricity that Idaho Power generates in each hour in order to offset losses from third parties wheeling through Idaho Power's transmission system.

The calculated hourly load required to serve third-party transmission losses is approximately 36 MW. Support for this calculation will be included in the Company's workpapers to be provided after this filing.

Q. Why is Idaho Power proposing to include the additional load required to serve third-party transmission losses in its load forecast?

A. As a part of the Company's most recent loss study performed in 2022, Idaho Power identified this additional load requirement that wasn't previously incorporated into its load forecast. With the advent of the Energy Imbalance Market ("EIM"), nearly all wheeling customers settle their losses financially, meaning Idaho Power incurs the cost to generate additional energy to account for these losses, and receives compensation from the third-party wheeling customer commensurate with this cost. This is in contrast to before the EIM, where wheeling customers also had the option to settle their losses physically – meaning the customer would generate or acquire the additional physical energy to account for the losses themselves, resulting in no additional required generation (and no corresponding additional payment) to Idaho Power.

As a result of nearly all losses being settled financially, the Company is proposing to incorporate the additional load required to serve third-party transmission wheeling losses into its load forecast, and thus also incorporate the cost of the additional generation into the total NPSE.

Q. Does the Company also include the associated revenue from third-party transmission losses as an offset to total NPSE?

A. Yes. The Company has included the offsetting revenues received from third-party transmission losses in its total NPSE calculation. This will be discussed in detail later in my testimony.

Hydro Modeling

Q. Please describe the changes to the hydro modeling process that occurred in the 2022 and 2023 APCU October Updates.

A. Idaho Power adopted new software called RiverWare for the 2022 October Update that replaced the then-existing modeling tools. It is an object-oriented, multi-objective river and reservoir modeling decision support system. Unlike the legacy tools, the RiverWare software is widely used, well-funded, and is actively being improved. Idaho Power procured a Snake RiverWare Planning Model, which covers the Snake River Basin from the headwater basins downstream to Brownlee Reservoir inflow, from the U.S. Bureau of Reclamation. Idaho Power also worked with RiverWare developers to develop a model of the Hells Canyon Complex with reservoir operating logic. The RiverWare models simulate reservoir operations, flows at each Idaho Power hydroelectric project, and an estimate of maximum available hydropower production given water resource constraints. With the change from the legacy systems to RiverWare, the hydrology period of record ("POR") was also updated in the 2022 October Update to 1951 - 2017 (67 water years). Idaho Power, Commission Staff, and the Citizens' Utility Board convened a workshop prior to the filing of the 2022 APCU to discuss the transition to RiverWare, and the stipulation from that case reflected modeling utilizing this new software.

Forecast hydro generation in the 2023 October Update was derived from the hydro modeling developed for the 2023 IRP. It included a shortened baseline hydrology POR of 1981 – 2017 (37 water years).

Q. Why were these changes made?

A. These changes were identified as part of a systematic review of modeling processes in advance of the 2023 IRP. The resulting updates to the hydro modeling provide an improved representation of observed hydrogeneration and incorporate the Company's best understanding of current and future changes to the distribution of hydropower. Additionally, the power generation parameters have been refined to account for tailwater effects and reduced generation efficiency under high flow conditions.

The shortened baseline hydrology POR focuses on the most recent years and current hydrologic conditions, while maintaining a sufficient number of years to capture the expected distribution of hydrogeneration. The POR change also allowed the Company to better align with industry standard practices, as federal and other hydro modeling entities use a "30-year normal" analysis period. In addition, the hydrologic modeling updates represent an improved calibration of the hydrologic model from a recent recalibration of key cloud seeding basins, which considered only years after 1980.

Idaho Power believes these updates result in a hydro modeling process and methodology that will provide a more accurate expectation of available hydro generation considering industry best practices and better capturing more recent forecast impacts, such as model recalibration and climate change.

Q. Has the Company validated the performance of the new hydro model?

A. Yes. Per the settlement stipulation agreed to in the 2022 APCU,[8] the Company performed a validation of the new hydro model. The model was validated using a baseline model run that represented historical observed cloud seeding operations along with current system operations and groundwater conditions.

Q. Please describe the Company's process for validating the performance of the new hydro model.

A. It is important to note that the 2023 IRP RiverWare model has been calibrated to

[8] *In the Matter of IDAHO POWER COMPANY, 2022 Annual Power Cost Update,* Docket No. UE 398. Order No. 22-191. (May 31, 2022)

represent how the current hydropower system would respond to a range of hydrologic variability and therefore is not expected to provide a perfect representation of historical observations. In addition, the RiverWare model does not account for any one-off historical operations or historical maintenance schedules, rather it represents typical operations and maintenance across the system. In other words, power generation simulated by the RiverWare model should be considered an estimate of the total available average megawatts ("aMW"). The model also does not account for operational reserves, load, or market conditions. Hydrologically speaking, the basin has seen significant increases to the diversion capacity of the groundwater recharge network above Milner Dam in recent years. This increased capacity is reflected in the RiverWare model and is another important difference between observed and simulated values.

Given that the model is not intended to provide a perfect representation of historical conditions, validation of the planning model involved a two-step process whereby a direct comparison of simulated and observed values of reservoir storage, flow, and power generation were used to check for general goodness of fit and screen for model bias. Discrepancies between observed and simulated values were then used to inform a deeper dive into model logic to determine if the response seen in the simulated record aligned with current operational guidance and system conditions.

Q. What were the results of the analysis?

A. Figure 1 and Figure 2 illustrate a comparison between observed and simulated power generation for the Hells Canyon Complex ("HCC") and the Idaho Power Hydropower System ("IPC Hydro"), excluding spring generation. Observed generation is shown in black, and simulated generation is shown in red. Idaho Power believes these results provide sufficient validation of the updated modeling process.

Figure 1: Observed vs Simulated Monthly aMW - HCC

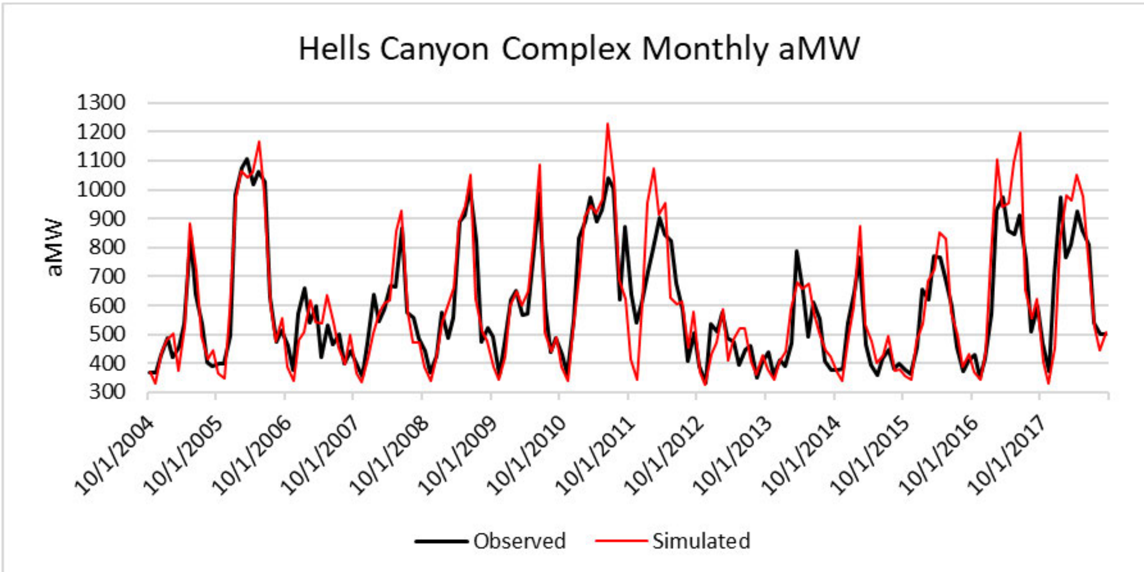
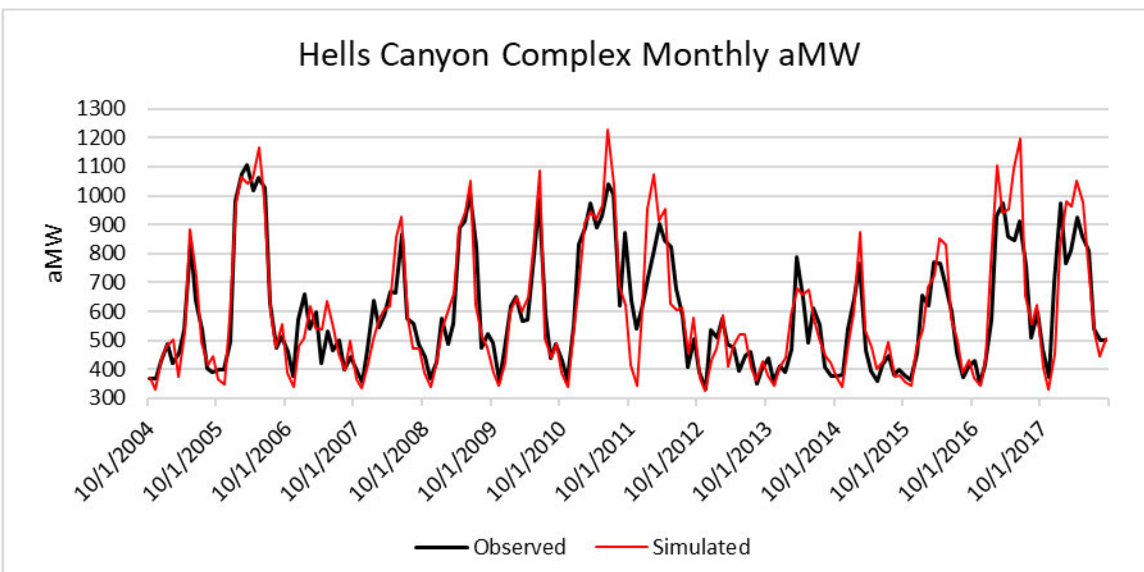


Figure 2: Observed vs Simulated Monthly aMW - IPC Hydro



Q. Were any additional changes made to the hydro modeling process for the 2024 APCU October Update?

A. No additional changes were made to the hydro modeling process for this year's October Update.

Other

Q. What other AURORA inputs were modified from last year's October Update?

A. The Company updated the maintenance rates, forced outage rates, heat rates, start costs, and other operating constraints for its thermal plants to better align the AURORA-dispatched generation with how the plants are typically operated. This is a consistent practice for every APCU filing.

The Company also included forecast demand response in the 2024 APCU model. Demand response was modeled according to the parameters of its three programs: A/C Cool Credit, Flex Peak Program, and Irrigation Peak Rewards. Based on actual 2022 participation, Idaho Power assumed the programs would provide a total of 320 MW of peak capacity from June 1 – September 15. No expenses associated with demand response were included in this filing.

Lastly, the Company included annualized forecast generation from its Oregon Community Solar Program, which is scheduled to come online by the end of 2023. No expenses associated with this program were included in this filing.

Q. Please describe any modifications made to the total NPSE calculation in this year's October Update.

A. Idaho Power made three modifications to the total NPSE calculation in this year's October Update. The first is the modification for Black Mesa Solar, which was introduced in last year's October Update. The second is a modification related to a new special contract with Lamb Weston, Inc. ("Lamb Weston"). The final modification is the inclusion of revenue received from third-party transmission wheeling losses.

Q. Please explain the modification related to Black Mesa Solar.

A. The Black Mesa Solar PPA was negotiated in conjunction with a new special contract with Micron Technology, Inc. ("Micron"). Micron's Special Contract states that Idaho Power will procure renewable resources to assist Micron in meeting a portion of its annual energy requirements with energy generated by those resources. While the renewable resource, Black Mesa Solar in this case, will not serve Micron directly, and rather will be connected to the Company's system, Micron will pay for all of the output. Because Micron will be paying for 100 percent of the Black Mesa Solar PPA, the cost of the PPA is excluded from the Company's calculation of NPSE. In addition, the corresponding portion of forecast sales from Micron met by the Black Mesa resource are removed from the total customer level sales for the test year. As a result, expenses associated with Black Mesa Solar have been excluded from the final NPSE and related Micron sales have been removed from the per-unit cost calculation. Line 20 of Exhibit 105 illustrates the total forecast generation from Black Mesa Solar of 0.099 million MWh and Line 29 shows the total expense of $0.

Q. Please explain the modification related to Lamb Weston.

A. In Order No. 35929, the Idaho Public Utilities Commission approved a new special contract with Lamb Weston for its Idaho operations. [9] Lamb Weston's special contract consists of a two-block pricing structure that includes an embedded-cost pricing block, Block 1, and marginal energy cost pricing block, Block 2. Block 2 consists of electricity consumed beyond 20 MW. According to their special contract, revenues from Block 2 energy sales should be treated as a surplus sale in NPSE calculations. As a result, revenues associated with Lamb Weston's forecast Block 2 energy sales have been

9 *In the matter of Idaho Power's Application for Approval of Special Contract and Tariff Schedule 34 to Provide Electric Service to Lamb Weston, Inc.,* Docket No. IPC-E-23-18. Order No. 35929 (September 21, 2023)

included as an offset to NPSE and the associated MWh have been removed from the per-unit cost calculation.

Line 52 of Exhibit 105 contains the forecast Block 2 revenue from Lamb Weston, referred to as Lamb Weston Surplus Sales, of $4.4 million. Line 58 contains the total forecast Block 2 energy sales. Line 59 contains the total customer level sales, net of Black Mesa Solar's generation and Lamb Weston Block 2 energy sales, which is used in the final per-unit cost calculation on Line 61.

Q. Please explain the modification related to third-party transmission wheeling losses.

A. As discussed earlier in my testimony, the load forecast used in this year's October Update includes an additional 36 MW in each hour to serve third-party transmission losses. As a result, Idaho Power has also included the revenue associated with this additional generation as an offset to total NPSE. This was calculated by multiplying Idaho Power's average hourly marginal resource price, as calculated by AURORA, by the 36 MW. Line 51 of Exhibit 105 contains the total revenue associated with third-party transmission losses.

Modeling Results

Q. Have you prepared an exhibit that summarizes the results of the AURORA model with all of the updated inputs described above?

A. Yes. Exhibit 101 shows the results of the AURORA modeling determination of normalized NPSE for the April 2024 through March 2025 test year. It presents the summary of results containing average variable power supply generation output and expenses based on 37 historical water conditions.

Q. Please summarize the sources and disposition of energy shown on Exhibit 101.

A. Hydro generation supplies 8.22 million MWh, approximately 48 percent (8.22 million MWh / 17.26 million MWh = 48 percent) of the generation mix. Thermal generation supplies 5.12 million MWh (Bridger 1.62, Valmy 0.47, Bridger Gas 0.64, Langley Gulch 1.83, Danskin 0.34, Bennett Mountain 0.23), approximately 30 percent (5.12 million MWh / 17.26 million MWh = 30 percent) of the generation mix. Purchases of power are made up of short-term and longer-term market purchases, PPAs, and PURPA. PURPA purchases reflect normalized and annualized generation levels and account for 3.11 million MWh. The generation volumes and costs associated with PURPA purchases are not shown on Exhibit 101; however, when combined with market purchases of 1.25 million MWh and PPAs of 1.68 million MWh, total purchases amount to 6.03 million MWh (3.11 million MWh + 1.25 million MWh + 1.68 million MWh = 6.03 million MWh) or approximately 35 percent of the generation mix. Of the 19.33 million MWh generated by the system, 17.26 million MWh are used for system loads while 2.06 million MWh are sold as surplus sales.[10]

Base Net Power Supply Expenses

Q. How are the Base Net Power Supply Expenses to be calculated for the October Update portion of the APCU according to the settlement stipulation approved in Order No. 08-238?

A. Per Order No. 08-238, the output of the AURORA model will 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 will be replaced with an average forward electric price curve.[11]

[10] Totals may not sum due to rounding.

[11] *Id* at 2, p. 3.

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-C hub. This methodology prescribes the use of a one-year average of the daily Mid-C forward price curves calculated from the previous 12 months of daily Mid-C heavy load ("HL") and Mid-C light load ("LL") forward price curves for the period starting in the April immediately following the current April through March test period. Forward prices are then adjusted for inflation back one year using the most recent Producer Price Index for Electric Power.

The re-pricing of market prices in the 2024 October Update is based upon the daily forward price curves for April 2025 through March 2026 as shown in Exhibit 102, which were then discounted for inflation back to April 2024 through March 2025 according to the quarterly inflation indices provided in Exhibit 103.

Q. Did Idaho Power make any adjustments to the re-pricing methodology approved in Order No. 08-238?

A. Yes. In Docket No. UE 384, Idaho Power proposed two adjustments to the re-pricing methodology approved in Order No. 08-238, which were subsequently approved in Order No. 21-165.[12] The Company incorporated both these adjustments to the re-pricing methodology used in this case. The first adjustment eliminated the fixed percentages, as prescribed in Order No. 08-238, used to adjust HL and LL forward prices depending on whether the applicable market energy was purchased or sold. Removing these fixed percentage adjustments results in market energy being re-priced at the established HL or LL forward market prices. The second adjustment

[12] *In the Matter of Idaho Power Company's 2023 Annual Power Cost Update*, Docket No. UE 384. Order No. 21-165 (May 27, 2023).

relates to the percentages used to determine the portion of AURORA-generated purchased power and surplus sales that occur in HL and LL hours. Historically, these percentages relied on the average of actual purchased power and surplus sales volumes in HL and LL hours for the years 2003-2007. In docket UE 384, Idaho Power updated the percentages based on an average of actual purchased power and surplus sales volumes in HL and LL hours for the years 2016 – 2020. The Company updated these percentages in this year's October update to incorporate data from 2018 – 2022.

Q. What is the monthly average forward price that is used for the re-pricing of purchased power and surplus sales volumes?

A. Exhibit 104 shows the monthly prices that are used for the re-pricing of purchased power and surplus sales volumes for the 2024 October Update. The prices range from a low of $33.29 per MWh to a high of $166.20 per MWh.

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

A. Lines 33 and 59 of Exhibit 101 show the purchased power expenses and surplus sales revenues, respectively, as determined by the AURORA modeling process. Lines 24 and 50 of Exhibit 105 show the same normalized generation dispatch with purchased power and surplus sales re-priced using the normalized forward price curve shown in Exhibit 104. A comparison of Exhibit 101 and Exhibit 105 demonstrates the changes due to re-pricing. Purchased power expenses increased by $66.6 million, moving from $50.7 million to $117.3 million. Surplus sales revenues increased by $57.3 million, moving from $106.6 million to $164.0 million. In this case, the NPSE resulting from the re-pricing methodology shown in Exhibit 105 is an increase in NPSE of $9.3 million as compared to the AURORA-generated expense shown on Exhibit 101. The differences for the re-pricing of purchased power of $66.6 million and surplus sales of $57.3 million are shown in Exhibit 108, Column J.

Energy Imbalance Market ("EIM") Benefits and Costs

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

A. Yes. The NPSE requested for approval in the 2024 October Update includes both the incremental benefits and costs associated with Idaho Power's participation in the Western EIM. This treatment is consistent with the methodology approved by the Commission in Idaho Power's 2018 - 2023 APCU dockets.[13]

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

A. Idaho Power is proposing to include $48.4 million in system EIM benefits as an offset to NPSE in the 2024 October Update. On an Oregon allocated basis, the EIM benefits to be included in the 2024 October Update are approximately $2.1 million.

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

A. The settled 2023 October Update system EIM benefit was $34.7 million, or $1.55 million on an Oregon allocated basis.

Q. How does CAISO quantify EIM benefits?

A. CAISO uses a counterfactual methodology in which dispatch for an EIM Balancing Authority Area ("BAA") mimics market operations without importing or exporting through EIM transfers. The counterfactual dispatch moves units inside the BAA to meet real-time imbalance based on economic merit order. CAISO's quantification of

[13] Docket Nos. UE 350, UE 350, UE 366, UE 384, and UE 414. Order Nos., 18-170, 19-189, 20-164, 21-165, and 23-184.

total estimated EIM benefits is the cost savings of the EIM dispatch compared to the counterfactual without EIM dispatch. In order to determine both EIM dispatch costs and counterfactual costs, CAISO relies upon bid prices submitted by EIM entities.

Q. What concerns does the Company have regarding CAISO's EIM benefits methodology as it relates specifically to Idaho Power?

A. One of the major assumptions CAISO makes in its benefits methodology, due to lack of other data, is that the bids submitted for each participating resource reflect the true dispatch costs, or the economic value, of those resources. For most resource types, this assumption may be reasonable; however, this assumption is not accurate for hydro resources.

Idaho Power bids hydro resources based on an operational need rather than actual dispatch cost. Additionally, Idaho Power utilizes various pricing tiers for its hydro resources to protect the water from overuse in the market and to adhere to regulated water management requirements.[14] The pricing tiers that Idaho Power uses are based upon certain operational parameters and can result in high bid prices when it is necessary to cease or limit water flows for a particular hydro resource's market participation. When Idaho Power operators move water into the higher tiers, which have a higher bid price, it is a response to operational needs and does not reflect market benefits.

Without adjusting for these operating scenarios, CAISO's EIM benefit methodology incorrectly reflects the bid tier price as the economic value of hydro in the determination of both counterfactual costs and EIM dispatch costs, thereby overstating the resulting benefits. In order for the EIM benefit calculation to properly

[14] Requirements may include flood control obligations, fish flow obligations, etc.

serve as an adjustment to modeled NPSE, Idaho Power adjusted the CAISO methodology as it pertains to the hydro pricing cost structure.

Q. Please describe the changes Idaho Power made to the hydro pricing cost structure for purposes of the EIM benefit calculation.

A. To reflect the correct economic value of the hydro dispatches in the EIM benefit calculation, Idaho Power made a two-part adjustment to the hydro cost structure. First, all hydro dispatch costs are held constant by applying a zero-cost. This satisfies a correction to CAISO's EIM counterfactual costs as there shouldn't be any costs associated with Idaho Power's dispatching up and down of its hydro resources to meet its load imbalances.

Holding the dispatch costs constant by applying a zero-cost also satisfies a correction to the EIM dispatch costs. The EIM is not a capacity market. Therefore, in a hydro system with limited ability to store water long-term, EIM imports (or the dispatching down and storage of the water) will have matching exports over a given time period (that hydrogeneration will be exported soon thereafter). When EIM hydro imports match exports over a measured period, in the case of Idaho Power's analysis an hourly basis,[15] dispatch costs should be held constant by replacing all tier prices with a zero cost. In this scenario, the actual benefit is the difference between the EIM import and export price. If the EIM dispatch cost is not held constant over the measured period, it results in an inaccurate benefit.

However, when hydro imports do not equal exports, it is necessary to value, or assign a cost to, the net import / exports to the market. This is the second part of the

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[15] The adjustments to the hydro pricing cost structure for the EIM benefit calculation are performed on an hourly basis at the recommendation of OPUC Staff. *In the Matter of Idaho Power Company's 2020 Annual Power Cost Update*, Docket UE 366, Idaho Power/300, Blackwell/17-18 (March 24, 2020).

adjustment Idaho Power made to the hydro pricing cost structure as it pertains to the EIM benefit calculation.

Q. Why is it necessary to value net imports and exports related to the EIM?

A. When imports exceed exports during the measured period, using a zero-cost value will underestimate benefits because it does not properly account for the value of imported energy that serves load (rather than hydro) and provides a benefit to the Company's customers. Conversely, when exports exceed imports during the measured period, the zero-cost value will inflate benefits because there aren't any costs assigned to the hydrogeneration that was moved into the market. In either scenario, the net imports / exports for the hydro resources will show a benefit at the EIM Locational Marginal Price ("LMP") because there are no costs associated with the hydro dispatches. As a result, it is necessary to make a second adjustment to the EIM benefit calculation to properly account for the hydro cost when imports do not equal exports for the measured period.

Q. Please explain the methodology used by the Company to value EIM net imports and exports of hydro-related energy.

A. Idaho Power adjusted the EIM benefits by replacing the zero-priced dispatch cost with the Powerdex Mid-C hourly market electricity price for all hours that the Company was a net importer or net exporter. Applying a market price to the net hydro import / export position allows the Company to properly account for the cost savings associated with imported energy that served load rather than hydro, or the costs associated with hydro energy exported to the EIM. The market prices were multiplied by the net import/export position and the adjusted savings/costs were applied to the zero-cost benefit method to accurately calculate EIM benefits for hydro resources.

Q. Did Idaho Power prepare an Exhibit to illustrate the adjustments to the hydro pricing cost structure of the EIM benefit calculation?

A. Yes. Exhibit 106 demonstrates Idaho Power's adjustments to the CAISO EIM benefit methodology as it pertains to the hydro pricing cost structure for the full 12-month period. Column A of Exhibit 106/1 includes CAISO's reported benefits for Idaho Power for September 2022 – August 2023 of $74.6 million. Column B illustrates Idaho Power's application of a zero-cost for all hydro tier prices when EIM imports equal exports on an hourly basis. This adjustment resulted in an EIM benefit of $43.1 million, a $31.5 million reduction from CAISO's stated EIM benefits for Idaho Power.

Column C of Exhibit 106/1 demonstrates the adjustment to the hourly net import / export position for the hydro resources. As discussed previously, Idaho Power assigned a value to the net import / export position for each hour based on the Powerdex Mid-C market electricity price. This adjustment resulted in a $5.3 million increase to Idaho Power's EIM benefit estimate.

Q. Please summarize the final estimate of EIM benefits to be included in the 2024 APCU.

A. The Company's EIM benefits forecast is based on the CAISO's EIM benefits reports, with necessary adjustments for hydro pricing as described in this testimony. As detailed in Exhibit 106, the Company's total estimated benefit for September 2022 through August 2023 is $48.4 million, or $2.1 million on an Oregon jurisdictional basis. The Company has included the estimate of EIM benefits as an offset to forecast NPSE for the October Update as shown in Exhibit 105.

Q. Please describe the incremental costs of Western EIM participation.

A. As stated previously, by participating in the Western EIM, the Company achieves NPSE savings, which benefit customers; however, to achieve such benefits, Idaho Power has incurred, and will continue to incur, incremental costs to participate in the

Western EIM, including software and metering investments and annual, ongoing operations and maintenance ("O&M") expenses. Consistent with prior APCU dockets, the Company has included EIM-related costs in the 2024 APCU. The EIM-related costs included in the 2024 October Update consist of the annual return on net rate base from the capital investment required to participate in the Western EIM, depreciation expense, and ongoing O&M expenses. On an Oregon allocated basis, the revenue requirement associated with EIM costs to be included in the 2024 October Update is $124,718, as shown in Exhibit No. 107.

Per-Unit Cost Calculation and NPSE Discussion

Q. What is the NPSE per-unit cost when you combine all of the quantifications described earlier?

A. Exhibit 105 shows total system NPSE of $483.7 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 15,792,635 MWh, resulting in a per-unit cost for the 2024 October Update of $30.63 per MWh ($483.7 million / 15.792 million MWh = $30.63 per MWh) to become effective on June 1, 2024.

Q. How does the 2024 October Update per-unit cost of $30.63 per MWh compare to the 2023 October Update per-unit cost?

A. The 2023 October Update per-unit cost, which became effective June 1, 2023, was $30.8 per MWh based upon a determination of total NPSE of $481.3 million

Q. Has the Company prepared an exhibit that demonstrates the changes in NPSE as compared to last year?

A. Yes. Exhibit 108 compares the AURORA-developed results, the re-pricing of purchased power and surplus sales, and the differences between the 2023 October Update and the 2024 October Update. Column H of Exhibit 108 shows the following:

(1) An increase in coal expenses of $2.5 million associated with a decrease of 0.37 million MWh in generation, (2) an increase in natural gas expenses of $110.1 million associated with an increase of 1.9 million MWh in generation, (3) a decrease in market purchased power expenses of $16.8 million associated with a decrease of 0.95 million MWh, (4) an increase in PPA expenses of $24.7 million associated with an increase of 0.69 million MWh, (5) an increase in PURPA expenses of $10.1 million associated with a decrease of 0.07 million MWh, and finally, (6) an increase in surplus sales revenue of $114.4 million associated with an increase of 0.97 million MWh.

Q. Can you elaborate more on the changes in generation from the 2023 October Update to the 2024 October Update?

A. Yes. To illustrate the changes in generation, Columns D (2023) and F (2024) of Exhibit 108 calculate the percentage of generation compared to total system load. For example, Column F, line 1, shows that hydro provided 48 percent of the generation to meet the total system load of 17,264,409 MWh (8,224,002 / 17,264,409 = 48 percent) compared to 49 percent in the 2023 October Update. Coal generation decreased from 14 percent to 12 percent, natural gas generation increased from 7 percent to 18 percent, market purchased power decreased from 13 percent to 7 percent, PPA generation increased from 6 percent to 10 percent, PURPA generation decreased from 19 percent to 18 percent, and lastly, surplus sales increased from 6 percent to 12 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.

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

A. Yes. The changes in expenses among resource types are relatively consistent with the changes in output, especially when considering the changes in the per-unit cost of the various resources. The changes in expenses for each resource type are also shown in Columns D (2023) and F (2024) of Exhibit 108 as follows: Coal expense remained unchanged at 17 percent of total NPSE, natural gas expense increased from 11 percent to 34 percent, market purchased power expense decreased from 28 percent to 24 percent, PPA expense increased from 12 percent to 17 percent, PURPA expense increased from 50 percent to 52 percent, and surplus sales revenue increased from 10 percent to 34 percent. Exhibit 108 demonstrates that the majority of movement in NPSE is related to the increase in natural gas generation and increase in economic surplus sales.

Q. What can be concluded from the information presented in Exhibit 108?

A. The information shown in Exhibit 108 confirms that the 15 percent decrease in coal generation combined with the 43 percent decrease in market purchases are being met with a 170 percent increase in natural gas generation and an 88 percent increase in surplus sales from last year's October Update.

Q. Did the Company comply with the methodology in Order No. 08-238 when it performed its analysis to determine the NPSE for the 2024 October Update?

A. Yes. The Company has complied with the methodology detailed in Order No. 08-238 for calculating this year's October Update.

Jurisdictional Allocation of NPSE

Q. How did the Company calculate the Oregon jurisdictional share of NPSE?

A. The Oregon jurisdictional share of NPSE is calculated by multiplying the system NPSE total per-unit cost of $30.63 per MWh by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April 2024 through March 2025 test period of 681,006.975 MWh, resulting in an Oregon jurisdictional share of NPSE of $20.86 million ($30.63 x 681,006.975 MWh = $20.86 million), as shown on Line 1 of Exhibit 109.

Quantification and Discussion of the APCU Revenue Requirement

Q. Based on the determination of the Oregon jurisdictional share of NPSE, what is the APCU revenue requirement for the 2024 October Update?

A. As shown on Line 3 of Exhibit 109, the APCU revenue requirement is $20.98 million. The APCU revenue requirement is calculated by adding the 2024 October Update Oregon jurisdictional share of NPSE of $20.86 million, Line 1, to the Oregon allocated EIM costs of $124,718 Line 2.

Q. What is the overall base revenue impact of this year's October Update compared to current revenue?

A. Exhibit 109 also reveals the revenue impact resulting from this year's October Update. As shown on Line 12, base NPSE recovery under current approved APCU rates is $21.09 million, whereas the proposed 2024 APCU October Update revenue requirement is $20.98 million, as shown on Line 3. The comparison of this year's October Update to current approved revenue indicates a decrease in Oregon customer rates of $101,556.

Rate Implementation

Q. What method of allocation did the Company use to spread the APCU revenue requirement associated with the 2024 October Update to the various customer classes?

A. The Company allocated the $20.98 million APCU revenue requirement associated with the 2024 October Update using the revenue spread methodology agreed upon in the settlement stipulation approved by Order No. 18-170.[16] Order No. 18-170 established a revenue spread methodology whereby the total 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. It should also be noted that the agreed upon revenue spread methodology included a provision that any rate increases resulting from application of this new methodology as applied to a customer class would be capped at 3 percent above the overall average rate increase on a percentage of total revenue basis. This cap was implemented to recognize that the movement to the new methodology could result in relatively large increases for individual classes within a single year. The cap is not applicable for the 2024 APCU.

Q. Have you provided an exhibit with the final proposed revenue spread?

A. Yes. The final proposed revenue spread resulting from the application of the stipulated methodology is provided in Exhibit 109.

Q. Have you prepared an exhibit showing the summary of the revenue impact resulting from the October Update proposed by the Company?

A. Yes. Exhibit 110 provides a summary of the revenue change resulting from this year's October Update as compared to current revenue.

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

A. Yes. Idaho Power will provide its supporting workpapers to Staff and CUB as part of the 2024 APCU filing. The Company intends to provide these workpapers within five business days of filing the 2024 APCU.

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[16] *In the Matter of Idaho Power Company's 2018 Annual Power Cost Update*, Docket No. UE 333. Order No. 18-170 (May 21, 2018).

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 101

Idaho Power Company's AURORA Modeled
Determination Of Normalized Power Supply
Expenses for April 1, 2024 – March 31, 2025

October 31, 2023

PCO NORMALIZED POWER SUPPLY EXPENSES FOR APR L 1, 2024 -- MARCH 31, 2025 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2024 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)	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													
2	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
3	AURORA Modeled Expense ($ x 1000)	$ 3,130 3	$ 2,026.6	$ 1,577.7	$ 4,945 0	$ 5,623.6	$ 4,408 6	$ 4,770.7	$ 7,713.9	$ 8,502.5	$ 7,121 3	$ 7,767 6	$ 2,146 9	$ 59,734.7
4	AURORA Modeled Handling Expense ($ x 1000)	$ (29 9)	$ (16.4)	$ (11.3)	$ (51.4)	$ (59.5)	$ (45 2)	$ (49.3)	$ (84.8)	$ (94.0)	$ (73 2)	$ (81.4)	$ (17 2)	$ (613.7)
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 3,160 2	$ 2,043.0	$ 1,588.9	$ 4,996.4	$ 5,683.1	$ 4,453 8	$ 4,820.0	$ 7,798.8	$ 8,596.6	$ 7,194 5	$ 7,848 9	$ 2,164.1	$ 60,348.4
6	IPC Share of OHAG Expense ($ x 1000)	$ (238.7)	$ (238.7)	$ (238.7)	$ (238.7)	$ (238.7)	$ (238.7)	$ (238.7)	$ (238.7)	$ (238.7)	$ (238.7)	$ (238.7)	$ (238.7)	$ (2,863.8)
7	Total 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													
8	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
9	AURORA Modeled Expense ($ x 1000)	$ 1,149 2	$ 1,521.4	$ 1,935.8	$ 2,324 3	$ 2,301.8	$ 1,991 9	$ 1,600.7	$ 2,186.1	$ 3,061.0	$ 2,504 5	$ 2,543 2	$ 2,066 9	$ 25,186.8
10	AURORA Modeled Handling Expense ($ x 1000)	$ 46 9	$ 62.2	$ 80.5	$ 98.1	$ 97.2	$ 83.4	$ 65.9	$ 93.0	$ 132.4	$ 103 6	$ 105 8	$ 84.1	$ 1,053.0
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 1,102 3	$ 1,459.2	$ 1,855.4	$ 2,226 2	$ 2,204.6	$ 1,908 5	$ 1,534.7	$ 2,093.1	$ 2,928.6	$ 2,400 8	$ 2,437.4	$ 1,982 8	$ 24,133.8
12	IPC Share of OHAG Expense ($ x 1000)	$ 257 9	$ 257.9	$ 257 9	$ 257 9	$ 257.9	$ 257 9	$ 257.9	$ 257.9	$ 257 9	$ 257 9	$ 257 9	$ 257 9	$ 3,095.2
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)	$ 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													
15	Energy (MWh)	17,734 0	53,924.4	74,312.9	83,875 8	86,529.9	72,290 8	67,114.9	51,169.1	25,689 9	22,380.4	21,498 3	59,865 8	636,386.2
16	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													
17	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
18	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													
19	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
20	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													
21	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
22	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
23	Fixed Capacity Charge - Gas Transportation ($ x 1000)	835 84	848 99	835.84	853.73	858.47	831.10	858.47	835 84	853.73	858.47	785.84	858.47	$ 10,114.8
	Purchased Power (Excluding PURPA)													
24	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
25	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
26	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
27	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
28	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
29	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
30	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
31	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
32	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
33	Market Expense ($ x 1000)	1,060 8	879.8	4,126.2	9,025 6	7,380.1	1,932 3	1,088.0	4,055.9	10,597.2	5,815 9	2,140.1	2,636 3	$ 50,738.2
34	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
35	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
36	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
37	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
38	Black Mesa Solar Expense ($ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	$ -
39	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
40	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
41	Total Expense Excl. PURPA ($ x 1000)	5,698.7	5,791.9	12,462.1	17,831 6	15,347.6	9,157 2	8,067.2	10,728.7	17,011.3	12,533 8	7,551 3	8,949 3	$ 131,130.7
	Storage													
42	Black Mesa Battery Energy (MWh)	(401 3)	(534.5)	(524.9)	(737 3)	(826.7)	(730 2)	(703.8)	(650.4)	(654.2)	(625 8)	(419 2)	(387.6)	(7,195 85)
43	80 MW Hemingway Battery Energy (MWh)	(2,583 0)	(2,215.7)	(1,735.6)	(1,750 6)	(1,749.2)	(1,856 9)	(2,537.8)	(2,458.9)	(2,465.7)	(2,794 3)	(2,546 5)	(2,868.5)	(27,562.75)
44	11 MW Grid Battery Energy (MWh)	(262.1)	(228.7)	(188.5)	(216 6)	(234.0)	(223 9)	(282.4)	(259.0)	(269.7)	(289 3)	(249 6)	(301.4)	(3,005.15)
45	Franklin Battery Energy (MWh)	(1,481 2)	(1,283.5)	(977 6)	(1,178 2)	(1,283.7)	(1,257.4)	(1,581.2)	(1,426.8)	(1,552 9)	(1,628.4)	(1,495.4)	(1,808 9)	(16,955.10)

46	36 MW Hemingway Battery Energy (MWh)	(875 6)	(759.2)	(595.1)	(706 5)	(768.8)	(745 0)	(944.2)	(849.4)	(915 6)	(951.4)	(871 0)	(1,070 0)	(10,051 60)
47	Total Storage (MWh)	(5,603 2)	(5,021.7)	(4,021.7)	(4,589 0)	(4,862.4)	(4,813.4)	(6,049.5)	(5,644.5)	(5,858.1)	(6,289.1)	(5,581 6)	(6,436.4)	(64,770.45)
48	Black Mesa Battery Expense ($ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
49	80 MW Grid Battery Expense ($ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
50	11 MW Grid Battery Expense ($ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Franklin Battery Expense ($ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
52	36 MW Hemingway Battery Expense ($ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Total Storage Expense ($ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response													
54	Energy (MWh)	-	-	4,917 5	10,748 8	1,542.3	-	-	-	-	-	-	-	17,208.6
55	Cost($ X 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Oregon Solar													
56	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
57	Cost($ X 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Surplus Sales													
58	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
59	Revenue ($ x 1000)	$ 11,166 2	$ 9,071.0	$ 5,649.1	$ 1,834 0	$ 3,017.8	$ 9,238.7	$ 9,978.9	$ 5,623.4	$ 3,692 9	$ 6,440 8	$ 12,204 3	$ 11,478.1	$ 89,395.0
60	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
61	Lamb Weston Sales ($ x 1000)	$ 227.16	$ 316.44	$ 445.95	$ 400.96	$ 451 55	$ 295 66	$ 313.55	$ 430.59	$ 409.59	$ 305.76	$ 422 51	$ 379.88	$ 4,399.6
62	Net Power Supply Expenses ($ x 1000)	$ 6,951 9	$ 9,296.4	$ 20,412.7	$ 37,207 0	$ 34,821.3	$ 18,735 5	$ 16,496.2	$ 28,407.4	$ 35,392.3	$ 26,743 9	$ 19,974 9	$ 18,136.7	$ 272,576.3

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 102

Mid-Columbia Forward Price Curves Discounted for Inflation

October 31, 2023

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
10/4/2022	38.35	36.35	37.65	110.90	123.60	110.90	53.30	59.05	69.25	69.85	59.90	49.05
10/5/2022	38.75	36.70	38.00	112.00	124.85	112.00	53.85	59.65	69.95	70.65	60.60	49.60
10/6/2022	39.90	37.80	39.10	115.30	128.55	115.30	55.45	61.40	72.00	72.95	62.55	51.20
10/7/2022	44.00	41.70	43.15	116.20	129.55	116.20	55.90	61.90	72.55	73.55	63.05	51.60
10/10/2022	43.85	41.55	43.00	115.85	129.15	115.85	55.75	61.70	72.35	73.30	62.80	51.40
10/11/2022	44.90	42.55	44.05	118.80	132.45	118.80	57.15	63.25	74.20	75.60	64.75	53.00
10/12/2022	45.85	43.45	45.00	121.30	135.25	121.30	58.35	64.60	75.75	77.50	66.35	54.30
10/13/2022	45.60	43.25	44.75	120.70	134.55	120.70	58.05	64.30	75.35	77.90	66.70	54.60
10/14/2022	45.60	43.25	44.75	120.70	134.55	120.70	58.05	64.30	75.35	77.90	66.70	54.60
10/17/2022	45.90	43.55	45.05	121.50	135.40	121.50	58.40	64.70	75.85	79.05	67.70	55.40
10/18/2022	45.60	43.25	44.75	120.65	134.45	120.65	58.00	64.25	75.30	80.20	68.70	56.20
10/19/2022	45.20	42.90	44.35	118.25	131.80	118.25	56.85	63.00	73.80	78.55	67.30	55.05
10/20/2022	44.80	42.55	44.00	117.25	130.70	117.25	56.40	62.45	73.20	77.80	66.65	54.55
10/21/2022	43.25	41.10	42.50	113.25	126.25	113.25	54.45	60.30	70.70	74.80	64.05	52.45
10/24/2022	43.85	41.65	43.10	114.80	127.95	114.80	55.20	61.10	71.65	75.95	65.05	53.25
10/25/2022	46.20	43.85	45.40	120.90	134.75	120.90	58.15	64.35	75.45	80.20	68.70	56.25
10/26/2022	47.50	45.10	46.70	124.30	138.55	124.30	59.80	66.15	77.60	83.90	71.90	58.85
10/27/2022	48.65	46.20	47.85	127.35	141.95	127.35	61.25	67.75	79.50	87.05	74.60	61.05
10/28/2022	48.60	46.15	47.80	127.30	141.90	127.30	61.20	67.70	79.45	87.00	74.55	61.00
10/31/2022	48.95	46.50	48.15	130.40	145.35	130.40	62.70	69.35	81.40	89.10	76.35	62.45
11/1/2022	48.85	46.40	48.05	130.20	145.15	130.20	62.60	69.25	81.30	88.95	76.20	62.35
11/2/2022	48.95	46.50	48.15	131.90	147.05	131.90	63.45	70.15	82.35	90.10	77.15	63.15
11/3/2022	50.15	47.65	49.30	135.10	150.65	135.10	65.00	71.85	84.35	91.30	78.20	64.00
11/4/2022	50.85	48.30	50.00	137.00	152.80	137.00	65.90	72.85	85.55	93.35	79.95	65.45
11/7/2022	51.00	48.45	50.15	138.30	154.20	138.30	66.50	73.55	86.35	94.20	80.70	66.05
11/8/2022	50.95	48.40	50.10	138.15	154.05	138.15	66.45	73.45	86.25	94.10	80.60	65.95
11/9/2022	50.95	48.40	50.10	138.20	154.10	138.20	66.45	73.45	86.25	94.10	80.60	65.95
11/10/2022	51.55	48.95	50.70	139.85	155.90	139.85	67.25	74.30	87.25	95.30	81.65	66.80
11/11/2022	51.05	48.45	50.20	138.45	154.35	138.45	66.55	73.55	86.35	94.25	80.75	66.05
11/14/2022	52.40	49.75	51.55	142.15	158.50	142.15	68.35	75.55	88.65	97.05	83.15	68.00
11/15/2022	53.10	50.40	52.25	144.05	160.65	144.05	69.25	76.55	89.85	98.20	84.15	68.80

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
11/16/2022	53.95	51.20	53.10	146.35	163.20	146.35	70.35	77.75	91.30	99.95	85.65	70.00
11/17/2022	53.80	51.05	52.95	148.20	165.25	148.20	71.25	78.75	92.45	101.10	86.65	70.80
11/18/2022	53.75	51.00	52.90	148.05	165.10	148.05	71.20	78.65	92.35	101.00	86.55	70.70
11/21/2022	53.80	51.05	52.95	148.25	165.30	148.25	71.30	78.75	92.45	101.10	86.65	70.75
11/22/2022	54.00	51.25	53.15	149.00	166.15	149.00	71.65	79.15	92.90	101.10	86.65	70.75
11/23/2022	54.70	51.95	53.85	151.00	168.35	151.00	72.60	80.20	94.15	102.60	87.95	71.80
11/24/2022	54.70	51.95	53.85	151.00	168.35	151.00	72.60	80.20	94.15	102.60	87.95	71.80
11/25/2022	54.50	51.80	53.65	150.50	167.80	150.50	72.35	79.95	93.85	102.25	87.65	71.55
11/28/2022	55.05	52.35	54.20	152.10	169.55	152.10	73.10	80.80	94.85	103.45	88.65	72.35
11/29/2022	54.65	51.95	53.80	151.00	168.30	151.00	77.80	85.95	100.90	103.45	88.65	72.35
11/30/2022	54.65	51.95	53.80	151.00	168.30	151.00	77.80	85.95	100.90	103.15	88.40	72.15
12/1/2022	54.65	51.95	53.80	151.05	168.40	151.05	77.85	86.00	100.95	103.20	88.45	72.20
12/2/2022	53.80	51.15	52.95	148.70	165.80	148.70	76.65	84.65	99.40	102.30	87.65	71.55
12/5/2022	53.65	51.00	52.80	148.35	165.40	148.35	76.45	84.45	99.15	102.00	87.40	71.35
12/6/2022	53.70	51.05	52.85	148.50	165.55	148.50	76.50	84.55	99.25	102.10	87.50	71.45
12/7/2022	54.70	52.00	53.85	151.35	168.70	151.35	77.95	86.15	101.15	103.70	88.90	72.55
12/8/2022	56.40	53.60	55.50	156.05	173.95	156.05	80.35	88.80	104.30	107.25	91.95	75.05
12/9/2022	57.75	54.85	56.80	159.70	178.05	159.70	82.25	90.90	106.75	110.00	94.30	76.95
12/12/2022	56.10	53.30	55.20	155.15	173.00	155.15	79.90	88.30	103.70	106.55	91.35	74.55
12/13/2022	55.80	53.00	54.90	154.30	172.10	154.30	79.45	87.85	103.15	105.90	90.80	74.10
12/14/2022	55.25	52.50	54.35	152.80	170.40	152.80	78.65	87.00	102.15	103.95	89.15	72.75
12/15/2022	57.25	54.40	56.35	153.25	170.90	153.25	78.90	87.25	102.45	104.75	89.85	73.30
12/16/2022	57.15	54.30	56.25	152.95	170.55	152.95	78.75	87.10	102.25	104.80	89.90	73.35
12/19/2022	56.65	53.85	55.75	151.65	169.10	151.65	78.10	86.35	101.40	103.80	89.05	72.65
12/20/2022	57.95	55.10	57.05	155.20	173.05	155.20	79.95	88.35	103.75	104.20	89.40	72.95
12/21/2022	58.50	55.60	57.60	156.65	174.65	156.65	80.70	89.15	104.70	106.55	91.40	74.60
12/22/2022	58.75	55.85	57.85	157.30	175.40	157.30	81.05	89.55	105.15	108.00	92.65	75.60
12/23/2022	58.85	55.95	57.95	157.55	175.65	157.55	81.15	89.70	105.30	108.20	92.80	75.75
12/27/2022	58.65	55.75	57.75	157.00	175.05	157.00	80.85	89.40	104.95	108.65	93.20	76.05
12/28/2022	58.50	55.60	57.60	156.55	174.55	156.55	80.60	89.15	104.65	108.20	92.80	75.75
12/29/2022	58.20	55.35	57.30	155.80	173.70	155.80	80.20	88.70	104.15	107.65	92.30	75.35

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
12/30/2022	58.20	55.35	57.30	155.75	173.65	155.75	80.15	88.65	104.10	107.60	92.25	75.30
1/2/2023	58.20	55.35	57.30	155.75	173.65	155.75	80.15	88.65	104.10	107.60	92.25	75.30
1/3/2023	58.20	55.35	57.30	155.75	173.65	155.75	80.15	88.65	104.10	107.60	92.25	75.30
1/4/2023	57.60	54.80	56.70	154.15	171.85	154.15	79.30	87.75	103.05	106.40	91.20	74.45
1/5/2023	57.35	54.60	56.50	153.55	171.15	153.55	79.00	87.40	102.65	105.95	90.80	74.10
1/6/2023	57.35	54.60	56.50	153.55	171.15	153.55	79.00	87.40	102.65	105.95	90.80	74.10
1/9/2023	57.50	54.75	56.65	154.00	171.65	154.00	79.25	87.65	102.95	106.30	91.10	74.35
1/10/2023	57.50	54.75	56.65	154.00	171.65	154.00	79.25	87.65	102.95	106.30	91.10	74.35
1/11/2023	56.65	53.90	55.80	151.65	169.05	151.65	78.05	86.30	101.40	104.50	89.55	73.10
1/12/2023	56.95	54.20	56.10	152.45	169.95	152.45	78.45	86.75	101.95	105.50	90.40	73.80
1/13/2023	55.90	53.20	55.05	149.60	166.75	149.60	77.00	85.15	100.05	103.35	88.55	72.30
1/16/2023	55.90	53.20	55.05	149.60	166.75	149.60	77.00	85.15	100.05	103.35	88.55	72.30
1/17/2023	54.80	52.15	53.95	146.60	163.40	146.60	75.45	83.45	98.05	101.05	86.60	70.70
1/18/2023	54.40	51.75	53.55	145.50	162.20	145.50	74.90	82.85	97.30	102.00	87.40	71.35
1/19/2023	54.30	51.65	53.45	145.30	161.95	145.30	74.80	82.70	97.15	101.85	87.25	71.25
1/20/2023	53.95	51.35	53.10	144.40	160.95	144.40	74.35	82.20	96.55	103.15	88.40	72.15
1/23/2023	53.90	51.30	53.05	144.30	160.85	144.30	74.30	82.15	96.50	103.10	88.35	72.10
1/24/2023	53.95	51.35	53.10	144.40	160.95	144.40	74.35	82.20	96.55	102.45	87.75	71.65
1/25/2023	52.25	49.75	51.45	139.90	155.95	139.90	72.05	79.65	93.55	99.00	84.80	69.25
1/26/2023	51.85	49.40	51.05	138.85	154.80	138.85	71.50	79.05	92.85	98.20	84.10	68.70
1/27/2023	51.95	49.45	51.15	139.05	155.05	139.05	71.60	79.15	93.00	98.60	84.45	68.95
1/30/2023	51.80	49.30	51.00	138.65	154.65	138.65	71.40	78.95	92.75	98.30	84.20	68.75
1/31/2023	51.85	49.35	51.05	138.80	154.85	138.80	71.50	79.05	92.85	98.45	84.30	68.85
2/1/2023	51.95	49.45	51.15	139.45	155.60	139.45	71.85	79.45	93.30	98.90	84.70	69.15
2/2/2023	50.40	48.00	49.65	140.50	156.80	140.50	72.40	80.05	94.00	99.20	84.95	69.35
2/3/2023	49.05	46.70	48.30	140.50	156.80	140.50	72.40	80.05	94.00	98.80	84.60	69.10
2/6/2023	48.80	46.45	48.05	139.75	155.95	139.75	72.00	79.60	93.50	98.35	84.20	68.75
2/7/2023	48.70	46.35	47.95	139.50	155.70	139.50	71.85	79.45	93.35	98.95	84.70	69.15
2/8/2023	48.40	46.10	47.65	138.65	154.80	138.65	71.45	79.00	92.80	98.30	84.15	68.70
2/9/2023	48.55	46.25	47.80	139.10	155.30	139.10	71.70	79.25	93.10	98.65	84.45	68.95
2/10/2023	48.80	46.50	48.05	139.85	156.15	139.85	72.10	79.70	93.60	98.95	84.70	69.15

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
2/13/2023	48.10	45.85	47.35	137.85	153.90	137.85	71.05	78.55	92.25	97.45	83.40	68.10
2/14/2023	49.05	46.75	48.30	140.55	156.90	140.55	72.45	80.10	94.05	99.05	84.75	69.20
2/15/2023	49.45	47.10	48.65	141.60	158.10	141.60	73.00	80.70	94.75	99.85	85.45	69.75
2/16/2023	50.00	47.65	49.20	143.20	159.90	143.20	73.80	81.60	95.80	101.05	86.50	70.60
2/17/2023	50.20	47.85	49.40	143.80	160.60	143.80	74.10	81.95	96.20	101.50	86.90	70.90
2/21/2023	50.00	47.65	49.20	143.15	159.90	143.15	73.75	81.60	95.75	101.00	86.50	70.55
2/22/2023	50.15	47.75	49.30	143.50	160.30	143.50	73.95	81.80	96.00	100.70	86.25	70.35
2/23/2023	50.95	48.55	50.10	145.85	162.90	145.85	75.15	83.15	97.55	102.05	87.45	71.30
2/24/2023	51.45	49.00	50.55	147.20	164.40	147.20	75.85	83.95	98.45	102.65	87.95	71.70
2/27/2023	51.50	49.05	50.60	147.40	164.65	147.40	75.95	84.05	98.60	102.80	88.10	71.80
2/28/2023	51.05	48.65	50.15	157.40	179.90	146.15	75.30	83.35	97.75	103.85	89.00	72.55
3/1/2023	51.20	48.80	50.30	157.90	180.45	146.65	75.55	83.60	98.05	104.20	89.30	72.80
3/2/2023	51.45	49.05	50.55	158.65	181.35	147.35	75.90	84.00	98.55	104.75	89.75	73.20
3/3/2023	51.70	49.30	50.80	159.40	182.20	148.05	76.25	84.40	99.00	107.10	91.75	74.85
3/6/2023	51.40	49.00	50.50	158.50	181.20	147.20	75.80	83.95	98.45	106.75	91.45	74.60
3/7/2023	51.60	49.20	50.70	159.05	181.85	147.75	76.05	84.25	98.80	107.15	91.80	74.90
3/8/2023	53.05	50.55	52.10	163.45	186.90	151.85	78.15	86.60	101.55	110.25	94.45	77.05
3/9/2023	52.95	50.45	52.00	163.10	186.50	151.55	78.00	86.40	101.35	110.25	94.45	77.05
3/10/2023	52.60	50.15	51.65	162.05	185.30	150.60	77.50	85.85	100.70	109.50	93.80	76.55
3/13/2023	52.75	50.30	51.80	162.55	185.85	151.05	77.75	86.10	101.00	110.20	94.40	77.05
3/14/2023	52.50	50.10	51.60	161.85	185.05	150.40	77.40	85.75	100.55	109.70	93.95	76.70
3/15/2023	52.45	50.05	51.55	161.75	184.95	150.30	77.35	85.70	100.50	109.65	93.90	76.65
3/16/2023	53.05	50.65	52.15	163.65	187.15	152.10	78.25	86.70	101.70	110.40	94.55	77.15
3/17/2023	52.95	50.55	52.05	163.35	186.80	151.80	78.10	86.55	101.50	111.00	95.10	77.60
3/20/2023	56.20	53.65	55.25	160.90	184.00	149.50	82.90	91.85	107.75	112.15	96.10	78.40
3/21/2023	56.95	54.35	56.00	163.05	186.45	151.50	84.00	93.10	109.20	113.25	97.05	79.15
3/22/2023	57.05	54.45	56.10	163.30	186.75	151.75	84.10	93.25	109.35	113.25	97.05	79.15
3/23/2023	56.45	53.85	55.50	161.55	184.70	150.10	83.20	92.25	108.15	112.05	96.00	78.30
3/24/2023	56.50	53.90	55.55	161.75	184.95	150.30	83.30	92.35	108.30	112.00	95.95	78.25
3/27/2023	57.05	54.45	56.10	163.35	186.75	151.80	84.10	93.25	109.35	112.25	96.15	78.40
3/28/2023	57.55	54.90	56.60	165.40	189.10	153.70	85.15	94.40	110.70	114.75	98.30	80.15

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Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
3/29/2023	57.05	54.40	56.10	170.30	194.70	158.25	87.65	97.20	113.95	117.70	100.80	82.20
3/30/2023	56.75	54.15	55.80	169.50	193.75	157.50	87.25	96.75	113.40	117.00	100.20	81.70
3/31/2023	56.30	53.70	55.35	168.10	192.15	156.20	86.55	95.95	112.50	116.00	99.35	81.00
4/3/2023	56.25	53.65	55.30	167.95	191.95	156.05	86.45	95.85	112.40	115.90	99.25	80.90
4/4/2023	56.00	53.40	55.05	167.25	191.15	155.40	86.10	95.45	111.95	115.30	98.70	80.45
4/5/2023	56.05	53.45	55.10	167.45	191.40	155.60	86.20	95.55	112.10	116.30	99.55	81.15
4/6/2023	55.40	52.80	54.45	165.45	189.10	153.75	85.15	94.40	110.75	114.85	98.30	80.10
4/10/2023	55.20	52.60	54.25	164.85	188.40	153.20	84.85	94.05	110.35	114.40	97.90	79.80
4/11/2023	54.85	52.30	53.90	163.85	187.25	152.25	84.35	93.45	109.65	113.60	97.20	79.25
4/12/2023	55.50	52.90	54.50	165.75	189.40	154.00	85.35	94.55	110.90	114.70	98.15	80.05
4/13/2023	55.45	52.90	54.45	165.60	189.20	153.85	85.25	94.45	110.80	115.15	98.55	80.35
4/14/2023	54.65	52.15	53.65	163.20	186.45	151.60	84.00	93.10	109.20	114.40	97.90	79.85
4/17/2023	54.60	52.10	53.60	163.05	186.30	151.50	83.95	93.05	109.10	114.30	97.80	79.80
4/18/2023	54.35	51.85	53.35	162.25	185.40	150.75	83.55	92.60	108.55	113.70	97.30	79.40
4/19/2023	54.30	51.80	53.30	162.15	185.30	150.65	83.50	92.55	108.50	113.65	97.25	79.35
4/20/2023	54.05	51.55	53.05	161.35	184.40	149.95	83.10	92.10	108.00	113.10	96.75	78.95
4/21/2023	53.60	51.10	52.60	160.00	182.90	148.70	82.40	91.35	107.10	112.15	95.90	78.25
4/24/2023	52.65	50.20	51.70	157.25	179.75	146.10	80.95	89.75	105.25	110.15	94.20	76.85
4/25/2023	53.00	50.55	52.05	158.30	180.95	147.10	81.50	90.35	105.95	110.90	94.85	77.40
4/26/2023	52.55	50.10	51.60	156.90	179.35	145.80	80.80	89.55	105.00	109.90	94.00	76.70
4/27/2023	52.25	49.80	51.30	155.95	178.30	144.95	80.30	89.00	104.35	110.05	94.15	76.80
4/28/2023	52.65	50.15	51.70	157.10	179.65	146.05	80.90	89.65	105.15	110.45	94.50	77.05
5/1/2023	52.35	49.85	51.40	156.15	178.55	145.15	80.40	89.10	104.50	109.75	93.90	76.55
5/2/2023	52.45	49.95	51.50	156.45	178.90	145.45	80.55	89.30	104.70	110.50	94.55	77.10
5/3/2023	51.95	49.50	51.00	154.75	177.20	144.10	79.80	88.45	103.70	109.40	93.60	76.35
5/4/2023	51.30	48.90	50.40	152.80	175.05	142.35	78.85	87.35	102.45	108.05	92.45	75.40
5/5/2023	51.30	48.90	50.40	152.80	175.05	142.35	78.85	87.35	102.45	108.05	92.45	75.40
5/8/2023	52.10	49.70	51.20	149.45	177.80	144.60	80.10	88.75	104.10	109.25	93.50	76.25
5/9/2023	52.90	50.45	51.95	149.10	177.95	144.75	80.20	88.85	104.20	109.90	94.10	76.70
5/10/2023	53.55	51.05	52.60	149.85	180.10	146.50	77.95	86.35	101.30	110.10	94.30	76.85
5/11/2023	53.60	51.10	52.65	149.65	180.25	146.65	78.00	86.45	101.40	110.30	94.50	77.00

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Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
5/12/2023	54.05	51.55	53.10	149.70	181.75	147.90	78.65	87.20	102.25	112.45	96.35	78.50
5/15/2023	54.25	51.70	53.25	149.70	182.35	148.40	78.90	87.50	102.60	113.20	97.00	79.00
5/16/2023	54.10	51.55	53.10	149.30	181.85	148.00	78.70	87.25	102.35	113.05	96.85	78.90
5/17/2023	54.20	51.65	53.20	149.60	182.20	148.30	78.85	87.45	102.55	113.30	97.05	79.05
5/18/2023	54.35	51.80	53.35	150.05	182.75	148.75	79.10	87.70	102.85	113.65	97.35	79.30
5/19/2023	54.25	51.70	53.25	149.70	182.35	148.40	78.90	87.50	102.60	113.35	97.10	79.10
5/22/2023	54.10	51.55	53.10	149.30	181.90	148.00	78.70	87.25	102.35	113.35	97.10	79.10
5/23/2023	54.10	51.55	53.10	149.30	181.90	148.00	78.70	87.25	102.35	113.35	97.10	79.10
5/24/2023	55.35	52.75	54.35	152.75	186.15	151.45	80.55	89.30	104.75	115.25	98.70	80.40
5/25/2023	55.35	52.75	54.35	152.70	186.15	151.45	80.55	89.30	104.75	115.25	98.70	80.40
5/26/2023	55.15	52.55	54.15	152.15	185.45	150.90	80.25	89.00	104.35	114.80	98.35	80.10
5/30/2023	55.10	52.50	54.10	151.95	185.20	150.70	80.15	88.90	104.20	114.65	98.20	80.00
5/31/2023	55.00	52.40	54.00	151.70	184.95	150.50	80.05	88.75	104.05	114.50	98.05	79.90
5/29/2023	55.15	52.55	54.15	152.15	185.45	150.90	80.25	89.00	104.35	114.80	98.35	80.10
6/1/2023	54.50	51.90	53.50	150.30	183.25	149.10	79.30	87.95	103.10	113.45	97.15	79.15
6/2/2023	53.95	51.40	52.95	148.80	181.40	147.60	78.50	87.05	102.05	112.55	96.35	78.50
6/5/2023	54.00	51.45	53.00	148.90	181.50	147.70	78.55	87.10	102.10	112.60	96.40	78.55
6/6/2023	53.65	51.10	52.65	147.85	180.25	146.70	78.00	86.50	101.40	112.15	96.00	78.20
6/7/2023	54.10	51.50	53.05	149.05	181.70	147.90	78.65	87.20	102.20	112.75	96.50	78.60
6/8/2023	54.00	51.40	52.95	148.75	181.35	147.60	78.50	87.00	102.00	115.15	98.55	80.25
6/9/2023	54.20	51.60	53.15	149.25	182.00	148.10	78.75	87.30	102.35	115.55	98.90	80.50
6/12/2023	54.25	51.65	53.20	149.40	182.20	148.25	78.85	87.40	102.45	115.65	99.00	80.55
6/13/2023	54.35	51.75	53.30	149.65	182.50	148.50	79.00	87.55	102.60	115.85	99.15	80.65
6/14/2023	54.35	51.75	53.30	149.65	182.50	148.50	79.00	87.55	102.60	115.85	99.15	80.65
6/15/2023	54.70	52.10	53.65	150.60	183.65	149.45	79.50	88.10	103.25	116.60	99.80	81.15
6/16/2023	54.55	51.95	53.50	150.15	183.10	149.00	79.25	87.85	102.95	115.65	99.00	80.50
6/20/2023	54.25	51.70	53.25	149.40	182.15	148.25	78.85	87.40	102.40	114.80	98.25	79.90
6/21/2023	55.05	52.50	54.05	151.65	184.90	150.50	80.05	88.70	103.95	116.55	99.75	81.10
6/22/2023	54.80	52.25	53.80	151.00	184.10	149.85	79.70	88.30	103.50	115.40	98.75	80.30
6/23/2023	54.75	52.20	53.75	150.85	183.90	149.70	79.60	88.20	103.40	115.25	98.65	80.20
6/26/2023	54.75	52.20	53.75	150.85	183.90	149.70	79.60	88.20	103.40	115.25	98.65	80.20

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Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
6/27/2023	54.00	51.50	53.05	148.85	181.45	147.70	78.55	87.05	102.05	113.70	97.35	79.15
6/28/2023	54.00	51.50	53.05	148.85	181.45	147.70	78.55	87.05	102.05	113.70	97.35	79.15
6/29/2023	54.15	51.65	53.20	149.25	181.95	148.10	78.75	87.30	102.30	114.00	97.60	79.35
6/30/2023	54.00	51.50	53.05	148.85	181.45	147.70	78.55	87.05	102.00	112.80	96.60	78.50
7/3/2023	54.00	51.50	53.05	148.85	181.45	147.70	78.55	87.05	102.00	112.80	96.60	78.50
7/5/2023	53.80	51.30	52.85	148.35	180.80	147.20	78.25	86.75	101.65	112.40	96.25	78.20
7/6/2023	53.60	51.10	52.65	147.85	180.20	146.70	78.00	86.45	101.30	111.75	95.70	77.75
7/7/2023	53.85	51.35	52.90	148.60	181.10	147.45	78.40	86.90	101.80	111.25	95.30	77.40
7/10/2023	53.95	51.45	53.00	148.90	181.45	147.75	78.55	87.05	102.00	111.50	95.50	77.55
7/11/2023	54.20	51.70	53.25	149.60	182.30	148.45	78.90	87.45	102.45	111.10	95.15	77.30
7/12/2023	53.65	51.20	52.70	148.10	180.45	146.95	78.10	86.55	101.40	109.95	94.15	76.50
7/13/2023	53.25	50.80	52.30	147.00	179.10	145.85	77.50	85.90	100.65	109.10	93.40	75.90
7/14/2023	53.70	51.25	52.75	148.25	180.65	147.10	78.15	86.65	101.50	109.95	94.15	76.50
7/17/2023	53.75	51.30	52.80	148.40	180.85	147.25	78.25	86.75	101.60	110.05	94.25	76.60
7/18/2023	53.45	51.00	52.50	147.55	179.85	146.40	77.80	86.25	101.05	108.90	93.25	75.80
7/19/2023	53.65	51.20	52.70	148.10	180.50	146.95	78.10	86.55	101.40	109.35	93.65	76.10
7/20/2023	53.50	51.05	52.55	147.65	179.90	146.50	77.85	86.25	101.05	109.00	93.35	75.85
7/21/2023	53.55	51.10	52.60	147.85	180.15	146.70	77.95	86.35	101.20	109.15	93.50	75.95
7/24/2023	53.85	51.35	52.90	148.60	181.10	147.45	78.35	86.80	101.75	109.75	94.00	76.35
7/25/2023	53.90	51.40	52.95	148.75	181.30	147.60	78.45	86.90	101.85	109.90	94.10	76.45
7/26/2023	54.45	51.95	53.50	150.30	183.20	149.15	79.25	87.80	102.90	111.10	95.10	77.25
7/27/2023	55.15	52.65	54.20	150.60	183.55	149.45	80.30	88.95	104.25	111.55	95.50	77.55
7/28/2023	55.80	53.30	54.85	152.45	185.80	151.25	81.25	90.05	105.50	112.30	96.15	78.10
7/31/2023	55.25	52.80	54.30	151.00	184.00	149.80	80.45	89.20	104.50	111.15	95.20	77.30
8/1/2023	55.05	52.65	54.10	150.50	183.40	149.30	80.20	88.90	104.15	110.75	94.90	77.05
8/2/2023	55.25	52.85	54.30	150.60	183.55	149.40	80.50	89.25	104.55	111.40	95.45	77.50
8/3/2023	55.95	53.50	54.95	151.10	184.15	149.90	81.50	90.35	105.85	112.40	96.30	78.20
8/4/2023	55.70	53.25	54.70	150.40	183.30	149.20	81.10	89.95	105.35	111.85	95.80	77.80
8/7/2023	55.50	53.05	54.50	149.80	182.60	148.65	80.80	89.60	104.95	111.40	95.40	77.50
8/8/2023	55.00	52.55	54.00	148.45	180.95	147.30	80.05	88.80	104.00	110.35	94.50	76.80
8/9/2023	55.95	53.45	54.90	147.60	179.90	146.45	81.40	90.30	105.75	111.65	95.65	77.70

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8/10/2023	56.30	53.80	55.25	147.85	180.20	146.70	81.90	90.85	106.40	112.15	96.10	78.05
8/11/2023	56.35	53.85	55.30	143.95	175.45	142.80	82.00	90.95	106.50	111.00	95.10	77.25
8/14/2023	56.00	53.55	54.95	143.10	174.40	141.95	81.50	90.40	105.85	112.15	96.10	78.05
8/15/2023	57.05	54.55	56.00	139.45	174.05	141.65	83.05	92.10	107.85	113.05	96.85	78.65
8/16/2023	56.60	54.15	55.55	137.60	171.75	139.80	82.40	91.40	107.00	111.95	95.90	77.85
8/17/2023	56.30	53.85	55.25	136.85	170.80	139.00	81.95	90.90	106.40	111.30	95.35	77.40
8/18/2023	56.65	54.15	55.60	135.80	169.45	137.90	82.45	91.45	107.05	111.10	95.15	77.25

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
8/21/2023	56.70	54.20	55.65	135.95	169.65	138.10	82.55	91.55	107.20	111.25	95.25	77.35
8/22/2023	56.00	53.55	55.00	134.30	167.60	136.45	81.55	90.45	105.90	109.90	94.10	76.40
8/23/2023	55.85	53.40	54.85	133.90	167.10	136.05	81.30	90.15	105.55	109.90	94.10	76.40
8/24/2023	55.25	52.85	54.30	132.50	165.35	134.65	80.45	89.20	104.45	108.75	93.10	75.60
8/25/2023	55.55	53.15	54.60	133.20	166.20	135.35	80.85	89.65	105.00	109.90	94.10	76.40
8/28/2023	54.90	52.55	53.95	131.65	164.25	133.75	79.90	88.60	103.80	109.55	93.80	76.15
8/29/2023	54.65	52.30	53.70	130.40	162.70	132.50	79.50	88.20	103.30	108.85	93.20	75.65
8/30/2023	54.55	52.20	53.60	130.15	162.35	132.25	79.35	88.00	103.10	108.65	93.00	75.50
8/31/2023	54.45	52.10	53.50	129.90	162.05	132.00	79.20	87.85	102.90	108.45	92.85	75.35
9/1/2023	54.55	52.20	53.60	130.15	162.35	132.25	79.35	88.00	103.10	108.65	93.05	75.50
9/5/2023	53.50	51.20	52.60	127.70	159.25	129.75	77.85	86.35	101.15	106.60	91.30	74.05
9/6/2023	53.30	51.00	52.40	127.25	158.70	129.30	77.60	86.05	100.80	106.25	91.00	73.80
9/7/2023	53.15	50.85	52.25	126.90	158.30	128.95	77.40	85.80	100.55	105.95	90.75	73.60
9/8/2023	52.85	50.55	51.95	126.20	157.40	128.20	76.95	85.30	100.00	105.35	90.25	73.20
9/11/2023	53.50	51.15	52.55	127.70	159.30	129.75	77.90	86.35	101.20	106.60	91.35	74.10
9/12/2023	53.95	51.55	53.00	128.75	160.60	130.80	78.55	87.05	102.05	106.10	90.90	73.75
9/13/2023	54.50	52.10	53.55	130.10	162.30	132.15	79.35	87.95	103.10	107.25	91.85	74.55
9/14/2023	54.80	52.40	53.85	130.80	163.15	132.85	79.80	88.40	103.65	107.85	92.35	74.95
9/15/2023	54.25	51.90	53.30	129.50	161.55	131.55	79.00	87.55	102.65	106.80	91.45	74.20
9/18/2023	53.25	50.95	52.30	127.10	158.55	129.10	77.55	85.95	100.75	104.80	89.75	72.80
9/19/2023	53.65	51.35	52.70	128.05	159.70	130.05	78.10	86.60	101.50	106.35	91.05	73.85
9/20/2023	54.30	51.95	53.30	129.55	161.55	131.55	79.00	87.60	102.70	107.60	92.15	74.70
9/21/2023	56.60	54.15	55.55	135.00	168.35	137.05	76.65	85.00	99.65	105.90	90.65	73.50
9/22/2023	55.30	52.90	54.25	131.85	164.40	133.85	74.85	83.00	97.30	107.25	91.80	74.45
9/25/2023	54.85	52.45	53.80	130.75	163.00	132.70	74.20	82.30	96.50	107.95	92.40	74.95
9/26/2023	54.50	52.10	53.45	129.95	161.95	131.85	73.75	81.80	95.90	107.25	91.80	74.45
9/27/2023	55.35	52.90	54.30	132.00	164.50	133.90	74.90	83.10	97.40	108.95	93.25	75.65
9/28/2023	55.35	52.90	54.30	132.00	164.50	133.90	74.90	83.10	97.40	108.95	93.25	75.65
9/29/2023	56.10	53.60	55.00	133.75	166.65	135.65	75.90	84.20	98.70	110.05	94.20	76.40
10/2/2023	56.10	53.60	55.00	133.75	166.65	135.65	75.90	84.20	98.70	110.05	94.20	76.40
10/3/2023	56.80	54.30	55.70	134.70	167.80	136.60	76.85	85.25	99.95	110.70	94.75	76.85

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
Average	53.42	50.91	52.51	146.11	170.32	143.88	76.33	84.54	99.15	105.56	90.41	73.67
Max HL	58.85	55.95	57.95	170.30	194.70	159.70	87.65	97.20	113.95	117.70	100.80	82.20
Min HL	38.35	36.35	37.65	110.90	123.60	110.90	53.30	59.05	69.25	69.85	59.90	49.05
Spread	20.50	19.60	20.30	59.40	71.10	48.80	34.35	38.15	44.70	47.85	40.90	33.15

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
10/4/2022	30.55	25.45	24.75	79.50	90.40	83.55	45.30	50.05	57.65	66.40	58.60	48.90
10/5/2022	30.95	25.80	25.10	80.60	91.65	84.65	45.85	50.65	58.35	67.20	59.30	49.45
10/6/2022	31.55	26.45	25.80	82.50	93.70	86.45	46.65	51.50	59.40	68.30	60.25	50.20
10/7/2022	33.65	28.60	28.15	78.65	89.30	82.40	44.40	49.00	56.55	68.90	60.75	50.60
10/10/2022	33.50	28.45	28.00	78.30	88.90	82.05	44.25	48.80	56.35	68.65	60.50	50.40
10/11/2022	34.55	29.45	29.05	81.25	92.20	85.00	45.65	50.35	58.20	70.95	62.45	52.00
10/12/2022	35.50	30.35	30.00	83.75	95.00	87.50	46.85	51.70	59.75	72.85	64.05	53.30
10/13/2022	35.25	30.15	29.75	83.15	94.30	86.90	46.55	51.40	59.35	73.25	64.40	53.60
10/14/2022	35.25	30.15	29.75	83.15	94.30	86.90	46.55	51.40	59.35	73.25	64.40	53.60
10/17/2022	35.55	30.45	30.05	83.95	95.15	87.70	46.90	51.80	59.85	74.40	65.40	54.40
10/18/2022	35.25	30.15	29.75	83.10	94.20	86.85	46.50	51.35	59.30	75.55	66.40	55.20
10/19/2022	34.85	29.80	29.35	80.70	91.55	84.45	45.35	50.10	57.80	73.90	65.00	54.05
10/20/2022	34.45	29.45	29.00	79.70	90.45	83.45	44.90	49.55	57.20	73.15	64.35	53.55
10/21/2022	32.90	28.00	27.50	75.70	86.00	79.45	42.95	47.40	54.70	70.15	61.75	51.45
10/24/2022	33.50	28.55	28.10	77.25	87.70	81.00	43.70	48.20	55.65	71.30	62.75	52.25
10/25/2022	35.25	30.25	29.90	81.95	92.95	85.65	45.85	50.60	58.45	71.20	62.55	52.05
10/26/2022	35.40	30.50	30.20	82.65	93.65	86.20	46.00	50.75	58.65	71.35	62.60	52.05
10/27/2022	35.55	30.70	30.45	83.30	94.30	86.75	46.15	50.90	58.85	71.50	62.70	52.10
10/28/2022	35.50	30.65	30.40	83.25	94.25	86.70	46.10	50.85	58.80	71.45	62.65	52.05
10/31/2022	35.85	31.00	30.75	86.35	97.70	89.80	47.60	52.50	60.75	72.35	63.40	52.65
11/1/2022	35.75	30.90	30.65	86.15	97.50	89.60	47.50	52.40	60.65	72.20	63.25	52.55
11/2/2022	36.60	31.65	31.40	89.70	101.50	93.25	49.35	54.45	63.00	75.85	66.40	55.15
11/3/2022	37.80	32.80	32.55	92.90	105.10	96.45	50.90	56.15	65.00	77.05	67.45	56.00
11/4/2022	37.75	32.80	32.60	92.90	105.10	96.40	50.80	56.00	64.85	78.10	68.35	56.70
11/7/2022	37.90	32.95	32.75	94.20	106.50	97.70	51.40	56.70	65.65	78.95	69.10	57.30
11/8/2022	37.45	32.55	32.35	93.10	105.30	96.60	50.80	56.05	64.90	78.05	68.35	56.65
11/9/2022	37.45	32.55	32.35	93.15	105.35	96.65	50.80	56.05	64.90	78.05	68.35	56.65
11/10/2022	38.05	33.10	32.95	94.80	107.15	98.30	51.60	56.90	65.90	79.25	69.40	57.50
11/11/2022	37.55	32.60	32.45	93.40	105.60	96.90	50.90	56.15	65.00	78.20	68.50	56.75
11/14/2022	38.60	33.60	33.50	96.30	108.80	99.75	52.25	57.65	66.75	79.75	69.80	57.80
11/15/2022	39.45	34.40	34.30	98.55	111.30	102.00	53.35	58.85	68.20	81.75	71.55	59.25

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Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
11/16/2022	40.15	35.10	35.00	100.50	113.45	103.95	54.25	59.85	69.40	83.20	72.75	60.25
11/17/2022	40.00	34.95	34.85	102.35	115.50	105.80	55.15	60.85	70.55	84.35	73.75	61.05
11/18/2022	39.95	34.90	34.80	102.20	115.35	105.65	55.10	60.75	70.45	84.25	73.65	60.95
11/21/2022	39.55	34.55	34.45	101.30	114.30	104.70	54.60	60.20	69.80	83.80	73.25	60.60
11/22/2022	39.50	34.50	34.40	101.40	114.40	104.75	54.60	60.20	69.80	83.80	73.25	60.60
11/23/2022	40.20	35.20	35.10	103.40	116.60	106.75	55.55	61.25	71.05	85.30	74.55	61.65
11/24/2022	40.20	35.20	35.10	103.40	116.60	106.75	55.55	61.25	71.05	85.30	74.55	61.65
11/25/2022	40.00	35.05	34.90	102.90	116.05	106.25	55.30	61.00	70.75	84.95	74.25	61.40
11/28/2022	40.55	35.60	35.45	104.50	117.80	107.85	56.05	61.85	71.75	86.10	75.25	62.20
11/29/2022	38.10	33.45	33.30	98.15	110.65	101.35	57.65	63.65	73.90	82.05	71.70	59.25
11/30/2022	38.10	33.45	33.30	98.15	110.65	101.35	57.65	63.65	73.90	83.70	73.15	60.45
12/1/2022	38.10	33.45	33.30	98.20	110.75	101.40	57.70	63.70	73.95	83.75	73.20	60.50
12/2/2022	38.85	34.05	33.85	100.00	112.85	103.35	58.95	65.05	75.50	82.50	72.10	59.60
12/5/2022	38.60	33.80	33.60	99.30	112.05	102.65	58.55	64.60	75.00	82.00	71.65	59.25
12/6/2022	38.65	33.85	33.65	99.45	112.20	102.80	58.60	64.70	75.10	82.10	71.75	59.35
12/7/2022	39.15	34.35	34.20	100.95	113.85	104.25	59.25	65.45	75.95	83.70	73.10	60.45
12/8/2022	40.85	35.95	35.85	105.65	119.10	108.95	61.65	68.10	79.10	87.25	76.15	62.95
12/9/2022	41.60	36.70	36.65	107.85	121.55	111.10	62.70	69.25	80.45	88.35	77.05	63.70
12/12/2022	39.95	35.15	35.05	103.30	116.50	106.55	60.35	66.65	77.40	84.90	74.10	61.30
12/13/2022	39.65	34.85	34.75	102.45	115.60	105.70	59.90	66.20	76.85	84.25	73.55	60.85
12/14/2022	39.95	35.05	34.95	103.10	116.35	106.45	60.40	66.75	77.45	83.75	73.15	60.55
12/15/2022	42.20	37.20	37.15	104.20	117.55	107.55	61.00	67.40	78.20	84.85	74.10	61.30
12/16/2022	42.25	37.20	37.15	104.25	117.60	107.60	61.05	67.45	78.25	84.90	74.15	61.35
12/19/2022	41.75	36.75	36.65	102.95	116.15	106.30	60.40	66.70	77.40	83.90	73.30	60.65
12/20/2022	41.95	37.05	37.00	103.75	117.00	107.00	60.60	66.95	77.70	84.35	73.65	60.95
12/21/2022	42.35	37.45	37.40	104.85	118.20	108.05	61.15	67.55	78.40	84.80	74.00	61.25
12/22/2022	42.60	37.70	37.65	105.50	118.95	108.70	61.50	67.95	78.85	86.25	75.25	62.25
12/23/2022	42.70	37.80	37.75	105.75	119.20	108.95	61.60	68.10	79.00	86.45	75.40	62.40
12/27/2022	42.35	37.50	37.40	104.85	118.20	108.05	61.10	67.55	78.35	84.85	74.00	61.25
12/28/2022	42.05	37.25	37.15	104.15	117.40	107.30	60.70	67.10	77.85	84.50	73.70	61.00
12/29/2022	42.20	37.40	37.25	104.50	117.80	107.70	60.95	67.40	78.20	84.65	73.80	61.10

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Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
12/30/2022	42.25	37.40	37.25	104.55	117.85	107.75	61.00	67.45	78.25	84.65	73.80	61.10
1/2/2023	42.25	37.40	37.25	104.55	117.85	107.75	61.00	67.45	78.25	84.65	73.80	61.10
1/3/2023	42.25	37.40	37.25	104.55	117.85	107.75	61.00	67.45	78.25	84.65	73.80	61.10
1/4/2023	41.65	36.85	36.65	102.95	116.05	106.15	60.15	66.55	77.20	83.45	72.75	60.25
1/5/2023	41.95	37.10	36.90	103.70	116.90	106.95	60.65	67.10	77.80	84.65	73.80	61.10
1/6/2023	41.95	37.10	36.90	103.70	116.90	106.95	60.65	67.10	77.80	84.65	73.80	61.10
1/9/2023	42.10	37.25	37.05	104.15	117.40	107.40	60.90	67.35	78.10	85.00	74.10	61.35
1/10/2023	42.10	37.25	37.05	104.15	117.40	107.40	60.90	67.35	78.10	85.00	74.10	61.35
1/11/2023	41.25	36.40	36.20	101.80	114.80	105.05	59.70	66.00	76.55	83.20	72.55	60.10
1/12/2023	41.55	36.70	36.50	102.60	115.70	105.85	60.10	66.45	77.10	84.65	73.80	61.10
1/13/2023	40.50	35.70	35.45	99.75	112.50	103.00	58.65	64.85	75.20	82.50	71.95	59.60
1/16/2023	40.50	35.70	35.45	99.75	112.50	103.00	58.65	64.85	75.20	82.50	71.95	59.60
1/17/2023	39.40	34.65	34.35	96.75	109.15	100.00	57.10	63.15	73.20	80.20	70.00	58.00
1/18/2023	38.90	34.15	33.85	95.40	107.65	98.65	56.40	62.35	72.25	80.95	70.60	58.50
1/19/2023	38.80	34.05	33.75	95.20	107.40	98.45	56.30	62.20	72.10	80.95	70.60	58.50
1/20/2023	38.45	33.75	33.40	94.30	106.40	97.55	55.85	61.70	71.50	79.15	69.05	57.20
1/23/2023	38.30	33.60	33.25	93.95	106.00	97.20	55.65	61.50	71.25	78.55	68.55	56.80
1/24/2023	38.00	33.35	33.00	93.20	105.15	96.45	55.20	61.00	70.70	77.90	68.00	56.35
1/25/2023	36.30	31.75	31.35	88.70	100.15	91.95	52.90	58.45	67.70	74.45	65.05	53.95
1/26/2023	35.90	31.40	30.95	87.65	99.00	90.90	52.35	57.85	67.00	73.65	64.35	53.40
1/27/2023	35.65	31.20	30.75	87.05	98.30	90.25	52.00	57.45	66.50	73.10	63.90	53.00
1/30/2023	35.50	31.05	30.60	86.60	97.80	89.80	51.75	57.20	66.20	72.45	63.35	52.55
1/31/2023	35.55	31.10	30.65	86.75	98.00	89.95	51.85	57.30	66.30	72.60	63.45	52.65
2/1/2023	35.65	31.20	30.75	87.40	98.75	90.60	52.20	57.70	66.75	73.05	63.85	52.95
2/2/2023	34.10	29.75	29.25	88.45	99.90	91.65	52.75	58.30	67.45	72.75	63.55	52.70
2/3/2023	32.75	28.45	27.90	88.45	99.90	91.65	52.75	58.30	67.45	72.35	63.20	52.45
2/6/2023	32.50	28.20	27.65	87.70	99.05	90.90	52.35	57.85	66.95	71.90	62.80	52.10
2/7/2023	32.40	28.10	27.55	87.45	98.75	90.65	52.20	57.70	66.80	72.50	63.30	52.50
2/8/2023	32.20	27.90	27.35	86.90	98.15	90.10	51.95	57.40	66.45	71.80	62.70	52.00
2/9/2023	32.25	27.95	27.40	87.00	98.25	90.20	52.00	57.45	66.50	72.15	63.00	52.25
2/10/2023	32.30	28.00	27.45	87.15	98.40	90.30	52.00	57.45	66.55	72.65	63.45	52.60

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Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
2/13/2023	31.60	27.35	26.75	85.15	96.15	88.30	50.95	56.30	65.20	71.15	62.15	51.55
2/14/2023	32.45	28.15	27.60	87.55	98.85	90.70	52.15	57.65	66.80	71.75	62.65	51.95
2/15/2023	32.85	28.50	27.95	88.60	100.05	91.75	52.70	58.25	67.50	72.55	63.35	52.50
2/16/2023	33.40	29.00	28.50	90.15	101.80	93.30	53.50	59.15	68.55	73.65	64.30	53.25
2/17/2023	33.45	29.05	28.55	90.35	102.00	93.45	53.55	59.20	68.65	73.90	64.50	53.40
2/21/2023	33.25	28.85	28.35	89.70	101.30	92.80	53.20	58.85	68.20	73.40	64.10	53.05
2/22/2023	33.40	28.95	28.45	90.05	101.70	93.15	53.40	59.05	68.45	73.10	63.85	52.85
2/23/2023	34.45	29.95	29.45	93.10	105.10	96.20	55.00	60.85	70.55	74.35	64.90	53.70
2/24/2023	34.65	30.20	29.70	93.80	105.85	96.85	55.30	61.20	70.95	76.30	66.60	55.10
2/27/2023	34.70	30.25	29.75	94.00	106.10	97.05	55.40	61.30	71.10	76.45	66.75	55.20
2/28/2023	34.30	29.85	29.35	99.00	114.10	95.90	54.80	60.65	70.35	77.50	67.65	55.95
3/1/2023	34.45	30.00	29.50	99.50	114.65	96.40	55.05	60.90	70.65	77.85	67.95	56.20
3/2/2023	34.70	30.25	29.75	100.25	115.55	97.10	55.40	61.30	71.15	78.40	68.40	56.60
3/3/2023	35.20	30.70	30.20	101.80	117.30	98.55	56.20	62.15	72.15	79.00	68.90	57.00
3/6/2023	34.85	30.40	29.90	100.80	116.15	97.60	55.70	61.60	71.50	78.55	68.50	56.65
3/7/2023	35.05	30.60	30.10	101.35	116.80	98.15	55.95	61.90	71.85	78.95	68.85	56.95
3/8/2023	35.80	31.40	30.95	103.80	119.60	100.35	57.00	63.05	73.20	80.85	70.50	58.25
3/9/2023	37.15	32.55	32.10	107.65	124.05	104.10	59.15	65.40	75.95	82.90	72.25	59.70
3/10/2023	36.80	32.25	31.75	106.60	122.85	103.15	58.65	64.85	75.30	82.15	71.60	59.20
3/13/2023	36.80	32.25	31.75	106.65	122.90	103.15	58.65	64.85	75.30	82.85	72.20	59.70
3/14/2023	36.55	32.05	31.55	105.95	122.10	102.50	58.30	64.50	74.85	82.35	71.75	59.35
3/15/2023	36.50	32.00	31.50	105.85	122.00	102.40	58.25	64.45	74.80	82.30	71.70	59.30
3/16/2023	40.60	35.65	35.10	107.75	124.20	104.20	59.15	65.45	76.00	83.05	72.35	59.80
3/17/2023	40.30	35.35	34.80	106.85	123.20	103.35	58.70	64.95	75.40	83.75	72.95	60.30
3/20/2023	43.55	38.45	38.00	104.40	120.40	101.05	63.50	70.25	81.65	84.90	73.95	61.10
3/21/2023	44.15	39.05	38.60	106.20	122.45	102.70	64.40	71.25	82.80	86.20	75.10	62.05
3/22/2023	45.60	40.35	39.90	100.85	116.25	97.50	66.55	73.60	85.55	86.30	75.20	62.15
3/23/2023	45.00	39.75	39.30	95.10	109.60	92.00	65.65	72.60	84.35	85.10	74.15	61.30
3/24/2023	45.05	39.80	39.35	90.30	104.05	87.35	65.75	72.70	84.50	85.05	74.10	61.25
3/27/2023	49.30	43.60	43.15	89.35	102.95	86.40	72.00	79.60	92.50	87.35	76.10	62.90
3/28/2023	49.75	44.05	43.60	88.40	101.85	85.40	73.05	80.75	93.85	88.35	76.90	63.55

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Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
3/29/2023	49.25	43.55	43.10	86.45	99.55	83.35	75.55	83.55	97.10	91.30	79.40	65.60
3/30/2023	51.20	45.25	44.80	85.65	98.60	82.60	75.15	83.10	96.55	90.60	78.80	65.10
3/31/2023	50.70	44.80	44.35	84.25	97.00	81.30	74.45	82.30	95.65	89.60	77.95	64.40
4/3/2023	50.65	44.75	44.30	84.10	96.80	81.15	74.35	82.20	95.55	89.50	77.85	64.30
4/4/2023	50.40	44.50	44.05	83.40	96.00	80.50	74.00	81.80	95.10	88.90	77.30	63.85
4/5/2023	51.05	45.05	44.60	84.55	97.35	81.60	74.95	82.85	96.35	89.25	77.55	64.05
4/6/2023	50.40	44.40	43.95	82.55	95.05	79.75	73.90	81.70	95.00	87.80	76.30	63.00
4/10/2023	50.20	44.20	43.75	81.95	94.35	79.20	73.60	81.35	94.60	87.35	75.90	62.70
4/11/2023	49.85	43.90	43.40	80.95	93.20	78.25	73.10	80.75	93.90	86.55	75.20	62.15
4/12/2023	50.50	44.50	44.00	82.85	95.35	80.00	74.10	81.85	95.15	87.65	76.15	62.95
4/13/2023	51.15	45.05	44.55	83.80	96.45	80.95	75.00	82.85	96.30	88.10	76.55	63.25
4/14/2023	50.35	44.30	43.75	81.40	93.70	78.70	73.75	81.50	94.70	87.35	75.90	62.75
4/17/2023	50.30	44.25	43.70	81.25	93.55	78.60	73.70	81.45	94.60	87.25	75.80	62.70
4/18/2023	50.05	44.00	43.45	80.45	92.65	77.85	73.30	81.00	94.05	86.65	75.30	62.30
4/19/2023	50.00	43.95	43.40	80.35	92.55	77.75	73.25	80.95	94.00	86.60	75.25	62.25
4/20/2023	49.75	43.70	43.15	79.55	91.65	77.05	72.85	80.50	93.50	86.05	74.75	61.85
4/21/2023	49.30	43.25	42.70	78.20	90.15	75.80	72.15	79.75	92.60	85.30	74.10	61.30
4/24/2023	48.35	42.35	41.80	76.50	88.20	74.25	70.70	78.15	90.75	83.30	72.40	59.90
4/25/2023	48.70	42.70	42.15	77.55	89.40	75.25	71.25	78.75	91.45	84.05	73.05	60.45
4/26/2023	48.25	42.25	41.70	76.15	87.80	73.95	70.55	77.95	90.50	83.45	72.55	60.05
4/27/2023	49.05	42.90	42.35	76.95	88.70	74.75	71.65	79.20	91.90	84.60	73.55	60.85
4/28/2023	49.45	43.25	42.75	78.10	90.05	75.85	72.25	79.85	92.70	85.00	73.90	61.10
5/1/2023	49.15	42.95	42.45	77.20	89.05	75.05	71.75	79.30	92.05	84.30	73.30	60.60
5/2/2023	49.25	43.05	42.55	77.55	89.45	75.35	71.95	79.50	92.30	86.95	75.60	62.50
5/3/2023	48.75	42.60	42.05	75.85	87.75	74.00	71.20	78.65	91.30	85.85	74.65	61.75
5/4/2023	48.10	42.00	41.45	73.90	85.60	72.25	70.25	77.55	90.05	84.50	73.50	60.80
5/5/2023	48.10	42.00	41.45	73.90	85.60	72.25	70.25	77.55	90.05	84.50	73.50	60.80
5/8/2023	48.90	42.80	42.25	70.55	88.35	74.50	71.50	78.95	91.70	85.70	74.55	61.65
5/9/2023	50.55	44.30	43.75	71.40	90.05	75.95	72.85	80.40	93.40	86.35	75.15	62.10
5/10/2023	50.25	44.05	40.45	70.80	90.50	76.25	74.30	82.00	95.25	87.20	75.85	62.70
5/11/2023	50.30	44.10	37.50	70.60	90.65	76.40	74.35	82.10	95.35	87.40	76.05	62.85

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Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
5/12/2023	50.75	44.55	35.95	70.65	92.15	77.65	75.00	82.85	96.20	89.55	77.90	64.35
5/15/2023	50.95	44.70	36.10	70.65	92.75	78.15	75.25	83.15	96.55	89.85	78.15	64.55
5/16/2023	50.70	44.50	34.95	70.15	92.10	77.65	74.90	82.80	96.10	88.95	77.40	63.90
5/17/2023	50.80	44.60	34.80	70.45	92.45	77.95	73.70	81.45	94.55	89.20	77.60	64.05
5/18/2023	50.95	44.75	34.95	70.90	93.00	78.40	73.95	81.70	94.85	89.55	77.90	64.30
5/19/2023	50.85	44.65	34.85	70.55	92.60	78.05	73.75	81.50	94.60	89.25	77.65	64.10
5/22/2023	50.70	44.50	34.65	70.15	92.15	77.70	73.55	81.30	94.35	88.75	77.25	63.75
5/23/2023	50.70	44.50	34.60	70.15	92.15	77.70	73.55	81.30	94.35	88.75	77.25	63.75
5/24/2023	51.95	45.70	35.55	73.60	96.40	81.15	75.35	83.30	96.70	90.65	78.85	65.05
5/25/2023	51.95	45.70	35.55	73.55	96.40	81.15	75.35	83.30	96.70	90.65	78.85	65.05
5/26/2023	51.75	45.50	35.35	73.00	95.70	80.60	75.05	83.00	96.30	90.20	78.50	64.75
5/30/2023	51.70	45.45	35.25	72.80	95.45	80.40	74.95	82.90	96.15	90.05	78.35	64.65
5/31/2023	51.60	45.35	35.10	72.55	95.20	80.20	74.85	82.75	96.00	89.90	78.20	64.55
5/29/2023	51.75	45.50	35.35	73.00	95.70	80.60	75.05	83.00	96.30	90.20	78.50	64.75
6/1/2023	51.10	44.85	34.50	71.15	93.50	78.80	74.10	81.90	95.00	88.85	77.30	63.80
6/2/2023	50.55	44.35	33.90	69.65	91.65	77.30	73.30	81.00	93.95	87.80	76.40	63.05
6/5/2023	50.60	44.40	32.85	69.75	91.75	77.40	73.35	81.05	94.00	87.85	76.45	63.10
6/6/2023	50.25	44.05	32.45	68.70	90.50	76.40	72.80	80.45	93.30	87.40	76.05	62.75
6/7/2023	49.50	43.40	32.10	68.25	89.75	75.75	71.70	79.20	91.90	87.80	76.40	63.05
6/8/2023	49.85	43.70	32.30	68.55	90.20	76.15	72.20	79.75	92.55	88.05	76.55	63.15
6/9/2023	50.05	43.90	32.50	69.05	90.85	76.65	72.45	80.05	92.90	88.30	76.80	63.35
6/12/2023	50.10	43.95	32.55	69.20	91.05	76.80	72.55	80.15	93.00	88.40	76.90	63.40
6/13/2023	50.20	44.05	32.65	69.45	91.35	77.05	72.70	80.30	93.15	88.60	77.05	63.50
6/14/2023	50.20	44.05	32.65	69.45	91.35	77.05	72.70	80.30	93.15	88.60	77.05	63.50
6/15/2023	50.55	44.40	33.00	70.40	92.50	78.00	73.20	80.85	93.80	89.35	77.70	64.00
6/16/2023	50.10	44.00	32.65	69.55	91.40	77.10	72.55	80.15	92.95	88.30	76.80	63.25
6/20/2023	49.80	43.75	32.40	68.80	90.45	76.35	72.15	79.70	92.40	87.45	76.05	62.65
6/21/2023	50.60	44.55	33.20	71.05	93.20	78.60	73.35	81.00	93.95	89.20	77.55	63.85
6/22/2023	50.35	44.30	32.95	70.40	92.40	77.95	73.00	80.60	93.50	88.05	76.55	63.05
6/23/2023	50.30	44.25	32.90	70.25	92.20	77.80	72.90	80.50	93.40	87.90	76.45	62.95
6/26/2023	50.30	44.25	32.90	70.25	92.20	77.80	72.90	80.50	93.40	87.90	76.45	62.95

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Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
6/27/2023	49.55	43.55	32.20	68.25	89.75	75.80	71.85	79.35	92.05	86.35	75.15	61.90
6/28/2023	49.55	43.55	32.20	68.25	89.75	75.80	71.85	79.35	92.05	86.35	75.15	61.90
6/29/2023	49.70	43.70	32.35	68.65	90.25	76.20	72.05	79.60	92.30	86.65	75.40	62.10
6/30/2023	49.20	43.25	32.00	67.75	89.10	75.25	71.35	78.80	91.35	85.55	74.45	61.35
7/3/2023	49.20	43.25	32.00	67.75	89.10	75.25	71.35	78.80	91.35	85.55	74.45	61.35
7/5/2023	49.00	43.05	31.80	67.25	88.45	74.75	71.05	78.50	91.00	85.15	74.10	61.05
7/6/2023	48.80	42.85	31.60	66.75	87.85	74.25	70.80	78.20	90.65	84.50	73.55	60.60
7/7/2023	48.55	42.65	31.50	66.75	87.80	74.15	70.40	77.75	90.15	85.20	74.15	61.10
7/10/2023	48.65	42.75	31.60	67.05	88.15	74.45	70.55	77.90	90.35	85.45	74.35	61.25
7/11/2023	48.90	43.00	31.85	67.75	89.00	75.15	70.90	78.30	90.80	85.30	74.25	61.15
7/12/2023	48.35	42.50	31.30	66.25	87.15	73.65	70.10	77.40	89.75	84.15	73.25	60.35
7/13/2023	47.95	42.10	30.90	65.15	85.80	72.55	69.50	76.75	89.00	83.30	72.50	59.75
7/14/2023	48.40	42.55	31.35	66.40	87.35	73.80	70.15	77.50	89.85	84.50	73.55	60.60
7/17/2023	48.45	42.60	31.40	66.55	87.55	73.95	70.25	77.60	89.95	84.60	73.65	60.70
7/18/2023	48.15	42.30	31.10	65.70	86.55	73.10	69.80	77.10	89.40	83.45	72.65	59.90
7/19/2023	48.35	42.50	31.30	66.25	87.20	73.65	70.10	77.40	89.75	85.35	74.30	61.25
7/20/2023	48.20	42.35	31.15	65.80	86.60	73.20	69.85	77.10	89.40	85.00	74.00	61.00
7/21/2023	48.25	42.40	31.20	66.00	86.85	73.40	69.95	77.20	89.55	85.15	74.15	61.10
7/24/2023	48.55	42.65	31.50	66.75	87.80	74.15	70.35	77.65	90.10	85.75	74.65	61.50
7/25/2023	48.60	42.70	31.55	66.90	88.00	74.30	70.45	77.75	90.20	85.90	74.75	61.60
7/26/2023	49.35	43.40	32.25	68.75	90.25	76.15	71.55	79.00	91.65	87.10	75.75	62.40
7/27/2023	50.05	44.10	32.95	69.05	90.60	76.45	72.60	80.15	93.00	87.55	76.15	62.70
7/28/2023	50.70	44.75	33.60	70.90	92.85	78.25	73.55	81.25	94.25	88.30	76.80	63.25
7/31/2023	50.15	44.25	33.05	69.45	91.05	76.80	72.75	80.40	93.25	87.15	75.85	62.45
8/1/2023	49.95	44.10	32.85	68.95	90.45	76.30	72.50	80.10	92.90	86.75	75.55	62.20
8/2/2023	50.15	44.30	33.05	69.05	90.60	76.40	72.80	80.45	93.30	87.40	76.10	62.65
8/3/2023	50.85	44.95	33.70	69.55	91.20	76.90	73.80	81.55	94.60	88.40	76.95	63.35
8/4/2023	50.60	44.70	33.45	68.85	90.35	76.20	73.40	81.15	94.10	86.95	75.70	62.30
8/7/2023	50.40	44.50	33.25	68.25	89.65	75.65	73.10	80.80	93.70	86.50	75.30	62.00
8/8/2023	49.90	44.00	32.75	66.90	88.00	74.30	72.35	80.00	92.75	85.45	74.40	61.30
8/9/2023	50.55	44.65	33.50	65.65	86.45	73.05	73.30	81.05	94.00	86.75	75.55	62.20

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Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
8/10/2023	50.90	45.00	33.85	65.90	86.75	73.30	73.80	81.60	94.65	87.25	76.00	62.55
8/11/2023	50.95	45.05	33.90	62.00	82.00	69.40	73.90	81.70	94.75	86.10	75.00	61.75
8/14/2023	50.60	44.75	33.60	61.15	80.95	68.55	73.40	81.15	94.15	85.75	74.70	61.50
8/15/2023	51.65	45.75	34.65	57.50	80.60	68.25	74.95	82.85	96.15	86.65	75.45	62.10
8/16/2023	51.20	45.35	34.20	55.65	78.30	66.40	74.30	82.15	95.30	85.55	74.50	61.30
8/17/2023	50.90	45.05	33.90	54.90	77.35	65.60	73.85	81.65	94.70	84.90	73.95	60.85
8/18/2023	51.25	45.35	34.25	53.85	76.00	64.50	74.35	82.20	95.35	85.00	74.00	60.90

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
8/21/2023	51.30	45.40	34.30	54.00	76.20	64.70	74.45	82.30	95.50	85.15	74.10	61.00
8/22/2023	51.85	45.85	34.45	53.65	76.00	64.60	75.25	83.20	96.50	84.05	73.15	60.25
8/23/2023	51.70	45.70	34.30	53.25	75.50	64.20	75.00	82.90	96.15	84.40	73.45	60.50
8/24/2023	50.65	44.75	33.45	51.40	73.10	62.20	73.50	81.20	94.20	84.25	73.30	60.40
8/25/2023	51.45	45.50	34.10	52.65	74.75	63.55	74.70	82.50	95.75	85.40	74.25	61.20
8/28/2023	50.80	44.90	33.45	51.10	72.80	61.95	73.75	81.45	94.55	83.40	72.55	59.80
8/29/2023	50.55	44.65	33.20	49.85	71.25	60.70	73.35	81.00	94.05	83.40	72.60	59.85
8/30/2023	51.30	45.30	33.65	50.45	72.15	61.45	74.45	82.20	95.45	83.20	72.40	59.70
8/31/2023	51.20	45.20	33.55	50.20	71.85	61.20	74.30	82.05	95.25	83.05	72.30	59.60
9/1/2023	51.30	45.30	33.65	50.45	72.15	61.45	74.45	82.20	95.45	83.25	72.50	59.75
9/5/2023	50.25	44.30	32.65	48.00	69.20	58.95	72.95	80.55	93.50	81.20	70.75	58.30
9/6/2023	50.05	44.10	32.45	47.55	68.65	58.50	72.70	80.25	93.15	81.20	70.75	58.30
9/7/2023	49.90	43.95	32.30	47.20	68.25	58.15	72.50	80.00	92.90	81.85	71.30	58.75
9/8/2023	49.60	43.65	32.00	46.50	67.35	57.40	72.05	79.50	92.35	81.25	70.80	58.35
9/11/2023	50.25	44.25	32.60	48.00	69.25	58.95	73.00	80.55	93.55	82.50	71.90	59.25
9/12/2023	50.70	44.65	33.05	49.05	70.55	60.00	73.65	81.25	94.40	82.00	71.45	58.90
9/13/2023	51.25	45.20	33.60	50.40	72.25	61.35	74.45	82.15	95.45	83.15	72.40	59.70
9/14/2023	51.55	45.50	33.90	51.10	73.10	62.05	74.90	82.60	96.00	83.75	72.90	60.10
9/15/2023	51.00	45.00	33.35	49.80	71.50	60.75	74.10	81.75	95.00	82.70	72.00	59.35
9/18/2023	50.00	44.05	32.35	47.40	68.50	58.30	72.65	80.15	93.10	81.30	70.85	58.40
9/19/2023	50.40	44.45	32.75	48.35	69.70	59.25	73.20	80.80	93.85	82.85	72.15	59.45
9/20/2023	51.05	45.05	33.35	49.85	71.55	60.75	74.10	81.80	95.05	84.10	73.25	60.30
9/21/2023	53.35	47.25	35.60	55.30	78.35	66.25	71.75	79.20	92.00	82.40	71.75	59.10
9/22/2023	53.25	47.05	35.10	53.40	76.20	64.55	71.60	79.05	91.80	83.80	72.95	60.05
9/25/2023	52.80	46.60	34.65	52.30	74.80	63.40	70.95	78.35	91.00	84.50	73.55	60.55
9/26/2023	52.45	46.25	34.30	51.50	73.75	62.55	70.50	77.85	90.40	84.00	73.15	60.20
9/27/2023	53.30	47.05	35.15	53.55	76.30	64.60	71.65	79.15	91.90	85.70	74.60	61.40
9/28/2023	53.30	47.05	35.15	53.55	76.30	64.60	71.65	79.15	91.90	85.70	74.60	61.40
9/29/2023	54.05	47.75	35.85	55.30	78.45	66.35	72.65	80.25	93.20	86.80	75.55	62.15
10/2/2023	54.05	47.75	35.85	55.30	78.45	66.35	72.65	80.25	93.20	86.80	75.55	62.15
10/3/2023	54.75	48.45	36.55	56.25	79.60	67.30	73.60	81.30	94.45	87.45	76.10	62.60

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
Average	44.28	38.85	34.22	80.53	96.85	84.84	64.26	70.99	82.35	82.77	72.17	59.64
Max LL	54.75	48.45	44.80	107.85	124.20	111.10	75.55	83.55	97.10	91.30	79.40	65.60
Min LL	30.55	25.45	24.75	46.50	67.35	57.40	42.95	47.40	54.70	66.40	58.60	48.90
Spread	24.20	23.00	20.05	61.35	56.85	53.70	32.60	36.15	42.40	24.90	20.80	16.70

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 103

Producer Price Index for Electric Power

October 31, 2023

Mnemonic:	FXPPIFU4.IUSA
Description:	Baseline Scenario (September 2
Source:	U.S. Bureau of Labor Statistics (
Native Frequency:	QUARTERLY
Geography:	United States
Last Updated:	9/11/2023
2020Q1	209.13
2020Q2	212.57
2020Q3	222.63
2020Q4	210.30
2021Q1	214.70
2021Q2	219.90
2021Q3	232.68
2021Q4	223.97
2022Q1	234.02
2022Q2	243.46
2022Q3	263.98
2022Q4	251.47
2023Q1	261.48
2023Q2	263.60
2023Q3	278.31
2023Q4	266.94
2024Q1	267.70
2024Q2	274.44
2024Q3	285.40
2024Q4	274.04
2025Q1	275.29
2025Q2	282.08
2025Q3	292.48
2025Q4	279.91
2026Q1	280.64
2026Q2	287.49
2026Q3	298.32
2026Q4	285.92

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 104

Forward Prices Used for Re-Pricing Purchased Power
and Surplus Sales

October 31, 2023

IDAHO POWER COMPANY
Mid-C Forward Price Curves Discounted for Inflation
Used to Re-Price Purchased Power and Surplus Sales for the October Update (UE 195 & 384 Settlement Methodology)

Line No.													
1	**Forward Curve Prices**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**
2	Relevant Quarter	2025 Q2	2025 Q2	2025 Q2	2025 Q3	2025 Q3	2025 Q3	2025 Q4	2025 Q4	2025 Q4	2026 Q1	2026 Q1	2026 Q1
3	Deflator	2.8208	2.8208	2.8208	2.9248	2.9248	2.9248	2.7991	2.7991	2.7991	2.8064	2.8064	2.8064
4	**Water Year**	**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	Relevant Quarter	2024 Q2	2024 Q2	2024 Q2	2024 Q3	2024 Q3	2024 Q3	2024 Q4	2024 Q4	2024 Q4	2025 Q1	2025 Q1	2025 Q1
6	Inflator	2.7444	2.7444	2.7444	2.8540	2.8540	2.8540	2.7404	2.7404	2.7404	2.7529	2.7529	2.7529
7	**Average Prices**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**
8	Mid-C HL	53.42	50.91	52.51	146.11	170.32	143.88	76.33	84.54	99.15	105.56	90.41	73.67
9	Mid-C LL	44.28	38.85	34.22	80.53	96.85	84.84	64.26	70.99	82.35	82.77	72.17	59.64
10	**Inflation Adjusted**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**
11	Mid-C HL	51.98	49.53	51.08	142.58	166.20	140.40	74.73	82.77	97.07	103.55	88.69	72.27
12	Mid-C LL	43.08	37.80	33.29	78.58	94.50	82.79	62.91	69.50	80.63	81.19	70.79	58.51
13	**Difference**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**
14	Mid-C HL	1.45	1.38	1.42	3.53	4.12	3.48	1.60	1.77	2.08	2.01	1.72	1.40
15	Mid-C LL	1.20	1.05	0.93	1.95	2.34	2.05	1.35	1.49	1.73	1.58	1.38	1.14

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 105

Total Normalized Base Power Supply Expenses for the 2024 October Update

October 31, 2023

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

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	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													
2	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
3	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													
4	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
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													
6	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
7	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													
8	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
9	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													
10	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
11	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													
12	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
13	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
14	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)													
15	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
16	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
17	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
18	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
19	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
20	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
21	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
22	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
23	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
24	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
25	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
26	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
27	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
28	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
29	Black Mesa Solar Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	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
31	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
32	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													
33	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)
34	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)
35	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)
36	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)
37	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)
38	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)
39	Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	Franklin Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	36 MW Hemingway Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Demand Response													
45	Energy (MWh)	-	-	4,917.5	10,748.8	1,542.3	-	-	-	-	-	-	-	17,208.6
46	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Oregon Solar													

47	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
48	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Surplus Sales													
49	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
50	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
51	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
52	Lamb Weston Surplus Sales ($ x 1000)	$ 227.16	$ 316.44	$ 445.95	$ 400.96	$ 451.55	$ 295.66	$ 313.55	$ 430.59	$ 409.59	$ 305.76	$ 422.51	$ 379.88	$ 4,399.6
53	Net Power Supply Expenses ($ x 1000)	$ 3,316.2	$ 6,697.1	$ 20,511.7	$ 53,235.5	$ 50,046.8	$ 10,556.7	$ 11,921.6	$ 29,380.0	$ 39,954.4	$ 26,124.6	$ 15,448.7	$ 14,652.4	**$ 281,845.7**
54	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
55	EIM Benefits ($ x 1000)													$ 48,437.14
56	Total Net Power Supply Expenses ($ x 1000)	$ 21,979.3	$ 27,726.5	$ 46,262.5	$ 82,099.4	$ 78,547.2	$ 31,311.0	$ 29,630.7	$ 46,500.2	$ 58,161.5	$ 43,045.2	$ 35,449.9	$ 31,457.8	**$ 483,734.0**
57	Sales at Customer Level (In 000s MWH)	1,116.88	1,175.16	1,335.23	1,642.25	1,729.50	1,517.33	1,173.32	1,105.03	1,254.63	1,377.24	1,322.13	1,217.40	15,966.107
58	Lamb Weston kWh Sales (In 000s MWH)	3.87	5.39	7.60	6.83	7.69	5.04	5.34	7.34	6.98	5.21	7.20	6.47	74.959
59	Sales at Customer Level - Net Black Mesa Solar & LW (In 000s MWH)	1,109.92	1,164.11	1,319.60	1,625.31	1,710.33	1,499.00	1,154.99	1,086.73	1,238.41	1,364.94	1,311.19	1,208.11	15,792.635
60	Hours in Month	720	744	720	744	744	720	744	721	744	744	672	743	8,760
61	Unit Cost / MWH (for PCAM)	$19.80	$23.82	$35.06	$50.51	$45.93	$20.89	$25.65	$42.79	$46.96	$31.54	$27.04	$26.04	**$30.63**

	Prices Used in Purchased Power & Surplus Sales Above:												
	Heavy Load												
62	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%
63	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
64	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%
65	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												
66	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%
67	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
68	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%
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 106

Energy Imbalance Market Benefits

October 31, 2023

IDAHO POWER COMPANY
2024 APCU October Forecast
Energy Imbalance Market Benefit Forecast
Based on September 22 - August 23 Historical Data

		(A)	(B)	(C)	(F)
Year	Month	CAISO Benefit	Zero-cost Hydro Adjustment	Hydro Net (Export)/Import Adjustment	Idaho Power EIM Benefit
2022	September	$ 6,072,419	$ 977,710	$ 1,495,439	$ 2,473,149
2022	October	$ 3,919,665	$ 425,799	$ 1,306,071	$ 1,731,870
2022	November	$ 3,998,746	$ (1,272,248)	$ 1,622,279	$ 350,031
2022	December	$ 9,260,913	$ 3,569,294	$ (1,265,437)	$ 2,303,857
2023	January	$ 6,312,513	$ 705,156	$ 2,358,528	$ 3,063,684
2023	February	$ 3,332,363	$ 1,601,595	$ 778,562	$ 2,380,158
2023	March	$ 3,674,335	$ 2,826,150	$ (9,341)	$ 2,816,808
2023	April	$ 8,429,942	$ 9,384,111	$ (155,659)	$ 9,228,452
2023	May	$ 17,861,967	$ 17,211,738	$ 14,615	$ 17,226,353
2023	June	$ 5,232,257	$ 4,032,572	$ (73,071)	$ 3,959,501
2023	July	$ 3,453,712	$ 2,255,875	$ (702,437)	$ 1,553,438
2023	August	$ 3,024,493	$ 1,401,903	$ (52,068)	$ 1,349,835
Total		**$ 74,573,326**	**$ 43,119,656**	**$ 5,317,480**	**$ 48,437,136**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 107

Energy Imbalance Market Costs

October 31, 2023

Idaho Power Company
2024 APCU
Oregon Jurisdictional EIM Revenue Requirement

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)	$90,770
Depreciation	$20,720
Taxes	($29,332)
Total Operating Expenses	**$82,157**
Net-to-Gross Tax Multiplier	1.347
Total Revenue Requirement	**$124,718**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 108

Year-Over-Year Differences in Modeled Normalized Power Supply Expenses

October 31, 2023

IDAHO POWER COMPANY
YEAR OVER YEAR DIFFERENCES IN AURORA DEVELOPED NPSE
2024 OCTOBER UPDATE

	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 October Update	2024 October Update	Resource Type	2023 October Update		2024 October Update		(B-A)	(E-C)	(C-A)	(E-B)
1	Hydro (MWh)	8,373,292	8,224,002	Hydro (MWh)	8,373,292	49%	8,224,002	48%	(149,290)	(149,290)	-	-
2	Coal (MWh)	2,457,884	2,083,094	Coal (MWh)	2,457,884	14%	2,083,094	12%	(374,789)	(374,789)	-	-
3	Natural Gas (MWh)	1,125,145	3,036,709	Natural Gas (MWh)	1,125,145	7%	3,036,709	18%	1,911,565	1,911,565	-	-
4	Market Purchased Power (MWh)	2,194,867	1,247,996	Market Purchased Power (MWh)	2,194,867	13%	1,247,996	7%	(946,871)	(946,871)	-	-
5	Purchased Power Agreements (MWh)	983,035	1,677,361	Purchased Power Agreements (MWh)	983,035	6%	1,677,361	10%	694,326	694,326	-	-
6	Storage (MWh)	(27,539)	(64,770)	Storage (MWh)	(27,539)	0%	(64,770)	0%	(37,232)	(37,232)	-	-
7	Other*	-	18,020	Other*	-		18,020	0%	18,020	18,020	-	-
8	PURPA (MWh)	3,179,923	3,106,875	PURPA (MWh)	3,179,923	19%	3,106,875	18%	(73,048)	(73,048)	-	-
9	Surplus Sales (MWh)	1,098,058	2,064,878	Surplus Sales (MWh)	1,098,058	-6%	2,064,878	-12%	966,820	966,820	-	-
10	System Generation (MWh)	18,286,606	19,329,287	System Generation (MWh)	18,286,606		19,329,287					
11	System Load (MWh)	17,188,548	17,264,409	System Load (MWh)	17,188,548	100%	17,264,409	100%	75,861	75,861	-	-
12	System Load (aMW)	1,957	1,971	System Load (aMW)	1,957		1,971		14	14	-	-
	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 October Update	2024 October Update	Resource Type	2023 October Update		2024 October Update		(B-A)	(E-C)	(C-A)	(E-B)
13	Hydro ($ x 1000)	$ -	$ -	Hydro ($ x 1000)	$ -		$ -		$ -	$ -	$ -	-
14	Coal ($ x 1000)	$ 82,110.1	$ 84,642.4	Coal ($ x 1000)	$ 82,110.1	17%	$ 84,642.4	17%	$ 2,532.3	$ 2,532.3	$ -	-
15	Natural Gas ($ x 1000)	$ 53,345.4	$ 163,430.7	Natural Gas ($ x 1000)	$ 53,345.4	11%	$ 163,430.7	34%	$ 110,085.3	$ 110,085.3	$ -	-
16	Market Purchased Power ($ x 1000)	$ 88,294.0	$ 50,738.2	Market Purchased Power ($ x 1000)	$ 134,158.6	28%	$ 117,331.0	24%	$ (37,555.8)	$ (16,827.6)	$ 45,864.7	66,593
17	Purchased Power Agreements ($ x 1000)	$ 55,740.2	$ 80,392.5	Purchased Power Agreements ($ x 1000)	$ 55,740.2	12%	$ 80,392.5	17%	$ 24,652.3	$ 24,652.3	$ -	-
18	Storage ($ x 1000)	$ -	$ -	Storage ($ x 1000)	$ -	0%	$ -	0%	$ -	$ -	$ -	-
19	PURPA ($ x 1000)	$ 240,220.1	$ 250,325.4	PURPA ($ x 1000)	$ 240,220.1	50%	$ 250,325.4	52%	$ 10,105.3	$ 10,105.3	$ -	-
20	Surplus Sales ($ x 1000)	$ (39,043.8)	$ (106,627.6)	Surplus Sales ($ x 1000)	$ (49,544.5)	-10%	$ (163,950.9)	-34%	$ (67,583.8)	$ (114,406.4)	$ (10,500.8)	(57,323)
21	EIM Benefits	$ (34,739.0)	$ (48,437.1)	EIM Benefits	$ (34,739.0)	-7%	$ (48,437.1)	-10%	$ (13,698.1)	$ (13,698.1)	$ -	-
22	Total System ($ x 1000)	$ 445,927.0	$ 474,464.5	Total System ($ x 1000)	$ 481,290.9	100%	$ 483,734.0	100%	$ 28,537.5	$ 2,443.1	$ 35,363.9	$ 9,269.4

*Includes Demand Response and Oregon Community Solar

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 109

Revenue Spread

October 31, 2023

Idaho Power Company
Stipulated Revenue Spread
2024 October Update

Line No.		
1	2024 October Update Oregon Jurisdictional Share of Base NPSE = $30.63/MWh x 681,006.975 MWhs =	$20,859,244
2	Oregon Allocated EIM Costs	$124,718
3	**Proposed October Update APCU Revenue Requirement**	**$20,983,961**

Line No.		TOTAL	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 2024 - March 2025 Generation Level Normalized Sales (kWh)**	**723,359,039**	207,731,587	108,327	21,705,069	121,161,337	15,526,472	3,235,789	405,130	182,431,542	98,906,339	71,620,864	5,786.71	496,109.60	24,685.89
5	**Class Share of April 2024 - March 2025 Generation Level Normalized Sales (kWh)**	**100%**	28.72%	0.01%	3.00%	16.75%	2.15%	0.45%	0.06%	25.22%	13.67%	9.90%	0.00%	0.07%	0.00%
6	**2023 October Update Class Allocated Base NPSE**	$ 20,983,961	$ 6,026,097	$ 3,142	$ 629,644	$ 3,514,776	$ 450,408	$ 93,867	$ 11,752	$ 5,292,166	$ 2,869,179	$ 2,077,654	$ 168	$ 14,392	$ 716
7	**June 2024 - May 2025 Loss-Adjusted Normalized Sales (kWh)**	**682,039,038**	193,137,625	100,679	20,224,490	112,965,508	14,785,591	3,144,596	377,216	173,740,839	96,233,282	66,838,913	5,388	461,927	22,985
8	**Proposed APCU Rates for 2024 October Update ($/kWh)**	**0.030767**	**0.031201**	0.031213	**0.031133**	**0.031114**	**0.030463**	**0.029850**	**0.031156**	**0.030460**	**0.029815**	**0.031084**	**0.031156**	**0.031156**	**0.031156**
9	**Proposed October Update APCU Revenue Requirement**	**$20,983,961**	$6,026,097	$ 3,142	$629,644	$3,514,776	$450,408	$93,867	$11,752	$5,292,166	$2,869,179	$2,077,654	$168	$14,392	$716

Line No.		TOTAL	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 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 2024 - May 2025 Loss-Adjusted Normalized Sales (kWh)**	**682,039,038**	193,137,625	100,679	20,224,490	112,965,508	14,785,591	3,144,596	377,216	173,740,839	96,233,282	66,838,913	5,388	461,927	22,985
12	**Base NPSE Recovered under Current APCU Rates**	**$21,085,517**	$6,081,860	$ 3,170	$636,088	$3,552,662	$450,278	$93,421	$11,878	$5,285,268	$2,853,420	$2,102,032	$170	$14,546	$724

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 110

Revenue Impact

October 31, 2023

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
APCU October Update
Effective June 1, 2024

Summary of Revenue Impact
Current Base Revenue to Proposed Base Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh) [1]	Current Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	Proposed Base NPSE Revenue	Total Proposed Base Revenue	Adjustments to Base Revenue	Percent Change Base to Base Revenue	Stipulated Revenue Increase 2 82% Cap	Revenue Requirement Shortfall
	Uniform Tariff Rates:												
1	Residential Service	1	13,812	193,137,625	$12,551,127	6,081,860	$18,632,987	$6,026,097	$18,577,224	($55,764)	(0 30)%	($55,764)	$0
2	Residential Service - Time-of-Day Pilot	5	4	100,679	$6,008	3,170	$9,178	$3,142	$9,150	($28)	(0 30)%	($28)	$0
3	Small General Service	7	2,745	20,224,490	$1,540,879	636,088	$2,176,966	$629,644	$2,170,522	($6,444)	(0 30)%	($6,444)	$0
4	Large General Secondary	9S	970	112,965,508	$5,593,473	3,552,662	$9,146,135	$3,514,776	$9,108,248	($37,886)	(0.41)%	($37,886)	$0
5	Large General Primary	9P	9	14,785,591	$637,024	450,278	$1,087,302	$450,408	$1,087,432	$131	0 01%	$131	$0
6	Large General Transmission	9T	1	3,144,596	$110,025	93,421	$203,446	$93,867	$203,893	$446	0 22%	$446	$0
8	Dusk to Dawn Lighting	15	0	377,216	$97,454	11,878	$109,332	$11,752	$109,206	($126)	(0.12)%	($126)	$0
9	Large Power Primary	19P	5	173,740,839	$5,898,626	5,285,268	$11,183,893	$5,292,166	$11,190,792	$6,899	0 06%	$6,899	$0
10	Large Power Transmission	19T	1	96,233,282	$3,384,930	2,853,420	$6,238,350	$2,869,179	$6,254,109	$15,759	0 25%	$15,759	$0
11	Agricultural Irrigation Service	24	2,309	66,838,913	$4,600,790	2,102,032	$6,702,822	$2,077,654	$6,678,444	($24,379)	(0 36)%	($24,379)	$0
12	Unmetered General Service	40	2	5,388	$186	170	$356	$168	$354	($2)	(0 50)%	($2)	$0
13	Street Lighting	41	27	461,927	$132,549	14,546	$147,095	$14,392	$146,941	($154)	(0.10)%	($154)	$0
14	Traffic Control Lighting	42	11	22,985	$1,643	724	$2,367	$716	$2,360	($8)	(0 32)%	($8)	$0
15	Total Uniform Tariffs		19,896	682,039,038	34,554,714	21,085,517	55,640,231	20,983,961	55,538,675	(101,556)	(0.18)%	(101,556)	0
16	Total Oregon Retail Sales		19,896	682,039,038	$34,554,714	$21,085,517	$55,640,231	$20,983,961	$55,538,675	($101,556)	(0.18)%		

(1) Updated June 2024-May 2025 Test Year

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document on the parties to Docket UE 414, Idaho Power's 2024 Annual Power Cost Update, on the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: October 31, 2023

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