BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	)	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MATTHEW T. LARKIN

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Matthew T. Larkin. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Revenue Requirement Senior Manager in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. I received a Bachelor of Business Administration degree in Finance from the University of Oregon in 2007. In 2008, I earned a Master of Business Administration degree from the University of Oregon. I have also attended electric utility ratemaking courses, including the *Electric Rates Advanced Course*, offered by the Edison Electric Institute, and *Estimation of Electricity Marginal Costs and Application to Pricing*, presented by National Economic Research Associates, Inc.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power as a Regulatory Analyst in January 2009. As a Regulatory Analyst, I provided support for the Company's regulatory activities, including compliance reporting, financial analysis, and the development of revenue forecasts for regulatory filings.

In January 2014, I was promoted to Senior Regulatory Analyst where my responsibilities expanded to include the development of complex cost-related studies and the analysis of strategic regulatory issues.

Since becoming the Revenue Requirement Senior Manager in March 2016, I have overseen the Company's regulatory activities related to revenue requirement, such as power supply expense modeling, jurisdictional separation studies, and Idaho Power's Open Access Transmission Tariff formula rate.

I. OVERVIEW

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

A. The purpose of my testimony is to present the forecast methodologies that were applied to the Company's 2022 financial data to arrive at the 2023 forecasted financial levels. Further, my testimony will describe the instructions that I provided to Company Witnesses Ms. Jessica G. Brady, Ms. Kelley Noe, and Ms. Paula Jeppsen with regard to the normalizing, annualizing, and other regulatory adjustments required to arrive at the 2023 test year revenue requirement.

Q. How is your testimony organized?

A. My testimony begins with an overview of direction I received from Vice President of Regulatory

Affairs Mr. Timothy E. Tatum regarding the development of the Company's 2023 Test Year ("2023 Test Year" or "Test Year"). I then detail two specific adjustments to the Company's 2023 Test Year regarding the recovery of costs related to Idaho Power's defined benefit pension plan and the recovery of non-fuel coal-related costs. Next, I discuss the broader methodologies utilized by the Company to forecast the remainder of the test year components. My testimony concludes with a summary of the direction I gave to other Company witnesses in developing the 2023 Test Year, and a quantification of the Company's requested Idaho jurisdictional revenue requirement.

Q. Did you consult with Mr. Tatum, Vice President of Regulatory Affairs, regarding the development of the 2023 Test Year?

A. Yes. The 2023 Test Year development methodology presented in my testimony is a direct result of numerous discussions with Mr. Tatum.

Q. Did Mr. Tatum provide you with any specific instructions or guidance regarding the development of the test year presented in this proceeding?

A. Yes. Mr. Tatum instructed me to develop a 2023 Test Year based on 2022 actual financial data in a manner similar to that presented to the Idaho Public Utilities Commission ("Commission") in the Company's last general rate case, IPC-E-11-08 ("2011 Rate Case"). However, Mr. Tatum instructed me to deviate from the methodology used in the 2011 Rate Case in a number of specific areas.

First, Mr. Tatum instructed me to set the recovery of 2023 Test Year pension expense at approximately $35 million, an increase above the level currently reflected in rates of $17 million. Second, Mr. Tatum directed me to maintain the North Valmy Power Plant ("Valmy") and the Jim Bridger Power Plant ("Bridger") non-fuel coal-related cost recovery at current levels, with the exception of collection related to previously deferred revenue requirement amounts. Third, Mr. Tatum directed me to update base net power supply expenses ("NPSE") to be included in base rates and tracked through the Power Cost Adjustment ("PCA") on a going forward basis. Fourth, Mr. Tatum instructed me to hold non-labor operations and maintenance ("O&M") expense at 2022 levels with specific adjustments for known and measurable changes. Fifth, Mr. Tatum instructed me to hold test year levels of wildfire mitigation costs to 2022 actual costs, and include amortization into rates of previously deferred wildfire mitigation costs, excluding deferred vegetation management costs, over a seven-year amortization period.

Prior to discussing the broader methodology utilized to develop the 2023 Test Year, I will first address the Company’s methodologies related to pension and non-fuel coal-related costs at Bridger and Valmy.

II. PENSION COST RECOVERY

Q. Please provide an overview of the regulatory treatment for the Company’s defined benefit pension plan expense in Idaho rate proceedings.

A. In Order No. 30333 issued in 2007, the Commission authorized Idaho Power to account for its defined benefit pension expense on a cash basis and to defer and account for accrued Statement of Financial Accounting Standards (“SFAS”) 87 / Accounting Standards Codification (“ASC”) 715 pension expense as a regulatory asset. Then in 2010, the Commission determined in Order No. 31003 that the previously authorized regulatory asset could be considered a balancing account to track, on a cumulative basis, the difference between the cash amounts contributed to the pension plan and the amounts included in rates. Additionally, the Commission determined that recovery of deferred cash contributions and ASC 715 expense and the associated amortization period were to be evaluated during a revenue requirement proceeding.

Q. Do customers benefit under the current regulatory treatment for pension expense?

A. Yes. The balancing account established by Order No. 31003 provides for a greater level of cost tracking that assures customers pay no more than the actual cost as well as providing a better opportunity to match costs with revenues. The balancing account is also an effective tool to mitigate financial market volatility as well as discount rate volatility. The balancing account results in the Company addressing both market and discount rate volatility while the customer impact of the volatility is mitigated. The balancing account also provides the Commission with the opportunity to determine an appropriate amortization period for rate recovery.

Q. What is the Company’s current annual level of pension expense recovery?

A. In Order No. 32248 issued in 2011 in Case No. IPC-E-11-04, the Commission authorized recovery of $17,153,713 per year.

Q. Aside from the current level of base rate recovery, have there been any other reductions to the balancing account?

A. Yes. Due to the Company’s revenue sharing mechanism,[1] from 2011 to 2014 the pension balancing account

[1] Case No. IPC-E-09-30, Order No. 30978. This ADITC/Revenue Sharing mechanism was subsequently extended, and percentages, thresholds, and accounting were modified by the Commission in Order Nos. 32424, 33149, and 34071.

was reduced by approximately $68 million, as earnings above a 10.5 percent return on equity were used to offset future rate increases associated with pension deferrals.

Q. What is the current balance in the pension balancing account?

A. As of December 31, 2022, the balance was $221 million.

Q. What is the Company's requested level of pension expense recovery in the 2023 Test Year?

A. At Mr. Tatum's direction, the Company is requesting $35 million of pension amortization, reflecting an approximate increase of $18 million compared to the amount currently in rates.

Q. Is there a risk to customers of over-recovery if assumptions regarding pension costs or funding levels change?

A. No. The existing balancing account methodology ensures that customers never pay more than actual pension costs. If future contributions are less than $35 million the balance in the account will be reduced sooner. If contributions continue to be higher than the recovery of $35 million, the pension balancing account will grow but will not impact customers without future rate approvals, as has been illustrated over the period since Idaho Power's last general rate case.

III. NON-FUEL COAL-RELATED COST RECOVERY

Q. How are non-fuel coal-related costs generally recovered in rates?

A. On May 31, 2017, the Commission authorized the Company in Order No. 33771 to establish a balancing account, with the necessary regulatory accounting, to track the incremental costs and benefits associated with the accelerated Valmy end-of-life as part of the Valmy levelized revenue requirement mechanism.[2] Similarly, on June 1, 2022, the Commission authorized the Company in Order No. 35423 to establish a balancing account, with the necessary regulatory accounting, to track the incremental costs and benefits associated with the Company's cessation of coal-fired operations at Bridger as part of the Bridger coal-related levelized revenue requirement mechanism.[3] The recovery of these amounts is embedded in the Company's currently-approved base rates.

Q. What direction did you receive from Mr. Tatum with regard to the inclusion of non-fuel coal-related costs in the 2023 Test Year?

A. Mr. Tatum directed me to maintain the Valmy and Bridger non-fuel coal-related cost recovery at current

[2] Case No. IPC-E-16-24, Order No. 33771.
[3] Case No. IPC-E-21-17, Order No. 35423.

levels, with the exception of collection related to previously deferred revenue requirement amounts.

Q. How did the Company achieve this directive?

A. This directive was achieved as reflected in Ms. Jeppsen's testimony and exhibits, through the removal of these costs from 2022 actuals. As discussed by Ms. Jeppsen, actual non-fuel coal-related costs at Bridger and Valmy were adjusted out of actual costs in all pertinent cost categories, including non-fuel O&M, electric plant-in-service, and property taxes.

Q. How is Idaho Power accounting for the existing cost recovery through these coal mechanisms in its presentment of the 2023 Test Year?

A. With regard to revenues, the Company's existing base rates already reflect the amount of current recovery of these levelized amounts, therefore the 2023 Test Year retail revenues calculated by Ms. Brady and provided to Ms. Noe reflect revenues the Company is currently receiving related to these levelized revenue requirements. With regard to costs, Idaho Power has quantified the current level of authorized cost recovery for both the Bridger coal-related and Valmy levelized revenue requirement mechanisms. Because coal-related Bridger and Valmy costs were removed from actual 2022 financials by Ms. Jeppsen, the Company has added the currently authorized Idaho jurisdictional recovery levels to the 2023 Test Year revenue requirement, as detailed in the jurisdictional separation study ("JSS") prepared by Ms. Noe. As described in the Direct Testimony of Mr. Tatum, these amounts also include the total incremental annual Bridger-related cost recovery associated with previously deferred revenue requirement amounts.

IV. TEST YEAR METHODS

Q. Will you briefly summarize how the Company developed its 2023 Test Year?

A. Yes. The development of the 2023 Test Year began with 2022 actual financial data ("2022 Actuals"). 2022 Actuals were compiled and adjusted by Ms. Jeppsen to reflect standard ratemaking adjustments and to arrive at 2022 adjusted actual financial information ("2022 Base"). The 2022 Base was then adjusted to reach 2023 forecasted financial levels ("2023 Unadjusted Test Year"). Finally, annualizing adjustments were made to the 2023 Unadjusted Test Year to reach the Company's 2023 Test Year.

Q. Which forecast methodologies were used to adjust the 2022 Base to the 2023 Unadjusted Test Year?

A. There were two primary methods developed and applied to the 2022 Base Year to forecast the 2023 Unadjusted Test Year. First, the Company used the unchanged 2022 Base Year financial data when the Company believed that certain amounts would continue to remain at 2022 levels or if account balances were relatively small. Alternatively, "Other Adjustments" were applied based upon known or probable factors for 2023 that relate to a particular account. Examples of these factors include, but are not limited to, new billing and volume contract terms, discontinued services, anticipated levels of economic activity, and existing regulatory commission orders.

Q. Have you prepared exhibits that list all accounts and identify the specific method used to forecast the 2023 Unadjusted Test Year?

A. Yes. I directed the preparation of Exhibit No. 25 to present a summarized list of all accounts to which the two previously discussed methods were applied. Each methodology is described in more detail within the Forecast Methodology Manual, provided as Exhibit No. 26, which was also prepared at my direction. To develop the Forecast Methodology Manual, the Company performed a review of each group of accounts included within the test year. Based upon specific knowledge and analysis of each account grouping, the Company either used 2022 Actuals or applied an Other Adjustment methodology to that account to represent an appropriate level of anticipated spending.

Q. Have the data and the associated adjustments made to your exhibits and supporting schedules been calculated on a total system basis?

A. Yes. Ms. Noe will address the determination of the Idaho jurisdictional test year values in her testimony.

Q. What are the major areas or groupings of financial accounts addressed by the methodologies included in the Forecast Methodology Manual (Exhibit No. 26)?

A. The major areas or groupings of financial accounts addressed in Exhibit No. 26 include Other Operating Revenues (Accounts 451, 454, and 456), Operation and Maintenance Expenses (Accounts 500 through 935), Depreciation and Amortization Expense (Accounts 403 and 404), and Electric Plant in Service (Account 101). A detailed discussion of the individual accounts and methods used is provided in Exhibit No. 26.

Q. Which methodology was used to forecast 2023 Other Operating Revenues (Accounts 447, 451, 454, and 456)?

A. Consistent with Mr. Tatum's directive, Surplus Sales Revenues (Account 447) were included in the Company's quantification of base NPSE as further detailed in Ms. Brady's testimony. The remaining Other Operating Revenues (Accounts 451, 454, and 456) were kept at year-end 2022 Actuals, with the exception of six items: 1) miscellaneous service revenues, 2) cogeneration and small power production, 3) revenues from dark fiber rents, 4) payments to water districts, 5) facilities charges, and 6) third-party transmission revenues.

Account 451 contains Miscellaneous Service Revenues, and was forecast based on proposed changes to Schedule 66 (the Miscellaneous Charges tariff that governs these offerings) that are further discussed in the Direct Testimony of Company Witness Mr. Riley Maloney. Cogeneration and small power production revenues were determined by applying a five-year compound average growth rate (“CAGR”), as the Company believes this method reflects a reasonable expectation for the 2023 timeframe. Revenues from dark fiber rents will cease in February 2023, therefore they were removed as a forecast adjustment. Payments from water districts were calculated based on a five-year average, as these payments fluctuate based on demand for water and availability. Expected facilities charge revenues were based on the Company’s proposed facilities charge rate filed in this case applied to expected applicable investment in the 2023 Test Year, as further addressed by Mr. Maloney. Network services and other long-term firm and point-to-point transmission revenues were projected based on information more reflective of current circumstances and an anticipated Open Access Transmission Tariff rate update in October 2023.

Q. Which methodology was used to forecast 2023 O&M Expenses (Accounts 500 through 935)?

A. Based on the instructions I received from Mr. Tatum, the general process to determine 2023 Test Year O&M began with the separation of the majority of O&M components into two elements: labor and non-labor. Each element was then forecast separately and allocated to the individual Federal Energy Regulatory Commission ("FERC") accounts.

Based upon the instructions I received from Mr. Tatum, there were several O&M accounts that were determined separately from this process. First, the base NPSE accounts tracked through the PCA were updated by Ms. Brady primarily utilizing the AURORA model. The PCA expense accounts include Fuel Expense (Accounts 501 and 547), Water for Power Expense (Account 536.003), Purchased Power Expense (Account 555), and Transmission of Electricity by Others (Account 565).

The Idaho Energy Efficiency Rider Expense (Account 908) was removed in its entirety from the 2023 Test Year, while the labor component was added back to this account, as discussed in the Direct Testimony of Mr. Tatum.

Incentive Expense (included in Account 920) was forecasted for 2023 to include only the normalized incentive components that are attributable to Customer Satisfaction and Reliability, consistent with the method approved in Case No. IPC-E-08-10 ("2008 Rate Case"), Order No. 30722, and filed in the Company's 2011 Rate Case. Incentive expense represents the "at-risk" portion of employees' total compensation package.

Pension Expense (Account 926) for the Idaho jurisdiction was increased to reflect $35 million in annual collection, as discussed previously in my testimony.

Regulatory Commission Expenses (Account 928) were adjusted to include known changes in amortizations for recovery of Commission-ordered intervenor funding.

Q. What methodology was used to forecast 2023 O&M labor expense?

A. The 2023 labor expense was forecasted by applying historical monthly labor cost relationships to the first two calendar months of 2023 actual labor costs. More specifically, the 2023 O&M labor forecast was developed by first calculating the three-year historical average of February year-to-date actual O&M labor costs as a percentage of the total year actual O&M labor costs. The resulting percentage was determined to be 16.0 percent. This percentage was then applied to the actual February 2023 year-to-date O&M labor to estimate the total 2023 O&M labor costs. The February amount was first reduced by pension expense and incentive expense. The resulting 2023 labor projection of $188.8 million was then allocated to the applicable FERC accounts based on 2022 actual labor charges to those same accounts.

This method is similar to that utilized by Commission Staff ("Staff") in the 2008 Rate Case to validate the Company's labor forecast as additional actual labor cost data became available throughout the test period, and mirrors the Company's filed approach in the 2011 Rate Case. A more detailed discussion of the labor-related O&M adjustment is provided in Exhibit No. 26, pages 5 and 6.

Q. Did Idaho Power make any adjustments to expected labor costs related to the Energy Efficiency Rider ("Rider")?

A. Yes. As described in the Direct Testimony of Mr. Tatum, in this case Idaho Power is proposing to transfer approximately $3.5 million in Rider-funded labor costs into base rates. As discussed later in my testimony, the movement of these labor costs from the Rider to base rate recovery is one of two rate neutral transfer adjustments the Company is proposing in this case.

Q. What methodology was used to forecast 2023 non-labor O&M expenses?

A. 2023 non-labor O&M expenses, excluding the accounts mentioned above, were projected to be equal to the 2022 actual expense level with adjustments only for relatively large known changes. At my direction, the O&M expenses were reviewed by subject matter experts to identify and adjust those areas, based on specific knowledge, where expense levels are expected to be materially different than those included in the 2022 Base. The review identified specific increases or decreases to the 2022 non-labor actual levels in the following categories:

- Idaho Fish and Game's Projected Hatchery Expense Increases
- Fleet Adjustment
- Water for Power Adjustment
- Langley and Bennett Mountain Plant Maintenance
- Western Resource Adequacy Program ("WRAP")[4] Costs
- Uncollectible / Bad Debt Expense
- Solar Payback Calculator

Actual 2022 non-labor O&M, excluding these items listed for known changes, equaled $157.6 million. Following the adjustments for significant known changes, non-labor O&M is projected to increase by $339,424, to $157.9 million. This reflects a non-labor O&M amount for the 2023 Test Year that has increased by less than 0.25 percent. A more detailed discussion of the non-labor O&M

[4] The WRAP and its associated benefits are currently the subject of an open case before the Commission (Case No. IPC-E-23-08).

adjustments is provided in Exhibit No. 26, pages 6 through 16.

Q. Is there any specific regulatory accounting treatment that the Company is seeking related to the list of known and measurable adjustments you just identified?

A. Yes. The Company requests specific regulatory accounting authority related to the known and measurable adjustment item "Langley and Bennett Mountain Plant Maintenance." As can be seen on pages 7 and 8 of Exhibit No. 26, Langley and Bennett Mountain Plant Maintenance — Account 554 was decreased from the 2022 Base by $3,423,030. For this non-labor component, this account was projected to be equal to the 5-year average. The 2022 base included cyclical plant maintenance related to Langley and Bennett Mountain major overhaul and inspections that do not occur on an annual basis.

Consistent with the accounting authority previously granted in Order No. 32426,[5] the Company requests the Commission authorize the deferral and amortization of annual differences between actual costs and the annual recovery amount authorized in this case to allow for a

[5] Order No. 32426 issued in Case No. IPC-E-11-08 approved a settlement stipulation containing the following ¶ 6(b) Amortization provision: "The Signing Parties agree to a deferral of $299,546 in expenses associated with the Bennett Mountain combustor inspection with a four-year period beginning on the date that the Company's new base rates become effective."

proper matching of cost and revenue for this periodic cost. The Company further recommends this treatment be allowed until new rates become effective in a future general rate case or are otherwise modified by the Commission.

Q. What accounting will the Company use to track the annual differences between actual costs and the annual authorized recovery amount?

A. Idaho Power will defer the difference between actual costs and the annual recovery amount to Account 182.3 Other Regulatory Assets with an offsetting entry to Account 554 Maintenance of Miscellaneous Other Power Generation Plant.

Q. What methodology was used to forecast 2023 Depreciation and Amortization Expense (Accounts 403 and 404)?

A. The 2023 depreciation expense, amortization expense, and related reserve accounts were calculated based on the monthly estimated 2023 plant balances. Depreciation rates authorized by Commission Order No. 35272 were used for the entire 2023 Test Year. The determination of the Depreciation and Amortization Expense adjustments is detailed in Exhibit No. 26, pages 16 and 17.

Q. Which methodology was used to forecast 2023 Electric Plant in Service (Account 101)?

A. Electric Plant in Service ("EPIS") is a function of multiple components, including actual year-end 2022 EPIS and construction work in progress ("CWIP") balances, estimated 2023 spending, expected 2023 closings of CWIP, and estimated retirements. Therefore, it was necessary to use several methodologies to develop the 2023 Unadjusted Test Year EPIS balances, which are detailed in Exhibit No. 26, pages 21 through 22.

To project 2023 construction expenditures and 2023 closings of CWIP to EPIS, at Mr. Tatum's instruction, the Company first bifurcated into two separate and distinct parts, those projects in excess of $8 million and those under $8 million.

Projects in excess of $8 million were reviewed by the individual project managers, who estimated the costs to complete and the in-service date of each project. The investment in projects under $8 million (excluding vehicles) closing to EPIS as a group, were forecast based on the five-year average of the percent of similar-sized projects to the previous year's CWIP balance multiplied by the year-end 2022 CWIP balance.

Q. Which methodology was used to forecast AFUDC associated with Hells Canyon relicensing CWIP?

A. While AFUDC continues to increase relating to the Hells Canyon relicensing efforts, the Company is requesting recovery of the same amount ($6,815,472) previously included in the 2011 Rate Case and subsequently approved in Order No. 32426. This adjustment is explained in greater detail in Exhibit No. 26, page 20.

V. ADDITIONAL ADJUSTMENTS

Q. In Ms. Jeppsen's testimony, she describes the various adjustments that were made to 2022 Actuals to arrive at the 2022 Base Year. Do these same adjustments need to be made in 2023?

A. No. These adjustments are standard ratemaking adjustments based on prior Commission orders and are adjustments to charges included in the 2022 Actuals. By removing them from 2022 Actuals prior to applying the various methodologies to arrive at the Company's proposed 2023 Unadjusted Test Year, the same adjustments are already accounted for.

Q. What were your instructions to Ms. Brady with regard to the determination of the test year retail sales revenues?

A. I instructed Ms. Brady to determine the 2023 Test Year retail sales revenues using the same methodology approved by the Commission in the 2008 Rate Case, Order No. 30722, and applied in the Company's 2011 Rate Case. That is, my instructions were to develop the test year retail sales revenues based upon forecasted billing determinants under normal weather and precipitation assumptions. As Ms. Brady will cover in greater detail in her testimony, the 2023 Test Year billing determinants were developed based on the Company's energy sales and customer count forecasts prepared for this case. To derive the demand-related billing determinants, historical demand-to-energy relationships were applied to the energy sales forecast. The forecasted billing determinants were then applied to the rates in effect at the time of the filing to determine the 2023 Test Year retail sales revenues.

Q. Was the customer, sales, and load forecast prepared at your direction?

A. Yes. The customer, sales, and load forecast for the 2023 Test Year was prepared at my direction. This forecast was utilized to determine the billing components for the 2023 retail sales revenue forecast, as well as the allocation factors utilized by Ms. Noe and Mr. Goralski as well.

Q. Did you direct Ms. Brady to make any adjustments to the 2023 retail sales revenues relative to the methodology utilized in the 2011 Rate Case?

A. Yes. Due to the Commission's approval of a revised special contract for electric service ("Special Contract") with Micron Technologies ("Micron") on March 9, 2022,[6] I directed Ms. Brady to exclude the component of Micron’s retail revenues that will be offset by generation from the Black Mesa Solar Facility (“Black Mesa”).

Q. Can you describe the mechanics of Micron’s revised Special Contract and how it pertains to the 2023 retail sales revenue calculation?

A. Per the terms of the revised Special Contact, a portion of Micron’s retail sales will be offset by generation from Black Mesa. Functionally, that means Micron will pay Idaho Power for 100 percent of the output from Black Mesa, which will offset the retail energy rates Micron would otherwise pay. Consequently, the portion of Micron’s sales offset by Black Mesa must be separately calculated from other retail revenues to ensure these contract components are appropriately accounted for throughout the various steps in the rate development process.

Q. Did you have any additional instructions for Ms. Brady?

A. Yes. In addition to the development of 2023 Test Year retail revenues, Ms. Brady is also the Company’s expert with regard to the modeling of base NPSE. As mentioned earlier in my testimony, Mr. Tatum directed me to update the PCA expense accounts to expected 2023 normalized

[6] Case No. IPC-E-22-06, Order Nos. 35482, 35607 and 35735.

levels. Consistent with this directive, Ms. Brady updated base NPSE as provided in Exhibit No. 30 to her testimony.

Q. When was base NPSE last updated in customer rates?

A. Idaho Power last updated base NPSE in customer rates through Order No. 33000 issued in Case No. IPC-E-13-20, which became effective June 1, 2014 ("2013 NPSE Update").

Q. Did you direct Ms. Brady to make any methodological changes to the determination of base NPSE relative to the method utilized in the 2013 NPSE Update?

A. Yes. Due to the aforementioned Black Mesa component of Micron's revised Special Contract, I directed Ms. Brady to include the generation from the Black Mesa project in the Company's resource stack, but exclude the corresponding costs from Account 555, as these costs will be directly paid for by Micron. Further, due to changes in conditions since the filing of the 2011 Rate Case, I also directed Ms. Brady to modify the treatment of Account 447.050, which reflects revenues received due to third-party transmission wheeling losses. Lastly, given current and expected changes in the Company's resource stack, I directed Ms. Brady to include in the 2023 Test Year the availability of gas-fired generation at Bridger units 1 and 2.

Q. What methodology adjustment was made related to Account 447.050, revenues from wheeling losses?

A. Account 447.050 reflects financial payments made to Idaho Power as compensation for the Company generating electricity to offset transmission losses to third parties wheeling through Idaho Power's transmission system. In past determinations of base NPSE, Idaho Power did not include 447.050 revenues in these quantifications, nor did it include any costs associated with the additional generation required to serve third party losses. In the current case, however, Idaho Power is proposing to include in its base NPSE determination both the cost of serving third party losses as well as the offsetting revenues received through Account 447.050. Therefore, Idaho Power added 36 average megawatts ("aMW") to its load forecast utilized for AURORA modeling purposes to account for this load service requirement, and Ms. Brady determined an offsetting revenue amount to include in Account 447.050.

Q. Why is Idaho Power proposing to make this methodological change?

A. Theoretically, the inclusion or exclusion of Account 447.050 and the corresponding cost to serve third party losses would ultimately yield the same result; the exclusion of these components would have no impact on revenue requirement because they would be entirely removed from the quantification, while the inclusion of these components would net to zero.

Additionally, when the 2013 NPSE Update was performed, third party wheeling customers had the option to account for wheeling losses in two ways: 1) financially – meaning the customer would pay Idaho Power to generate the additional energy to account for the losses, or 2) physically – meaning the customer would generate or acquire additional physical energy to account for the losses themselves, resulting in no additional payment to Idaho Power. However, with the advent of the energy imbalance market ("EIM"), nearly all wheeling customers now settle their losses financially, meaning they pay Idaho Power to generate the physical energy to account for wheeling losses through the Company's system. Because of this, the Company is proposing to modify the base NPSE methodology to include both the cost to serve third-party wheeling losses and the offsetting revenues received by the Company.

Q. Given this change, is the Company proposing that Account 447.050 would be included in the PCA as well?

A. Yes. Under the Company's proposal, Account 447.050 would become part of base NPSE utilized in PCA calculations as of the effective date of rates resulting from this case.

Q. What direction did you give Ms. Brady with regard to the Company's resource stack?

A. The timing of Idaho Power's 2023 Test Year corresponds with changes in the Company's resource stack, resulting in the need for an adjustment to assumed resource availability. Under current operations, the Jim Bridger Power Plant consists of four coal-fired units. However, the Company will cease coal-fired operations at units 1 and 2 at year-end 2023, converting these units to natural gas, with an expected online date of summer 2024. Because of this timing, I directed Ms. Brady to model the availability of two gas units and two coal units at Bridger, which better aligns with expectations on a going forward basis.

Because the Company's requested effective date in this case is January 1, 2024, and because the PCA will capture differences between actual NPSE and base NPSE on a going forward basis until base NPSE are reset in a future proceeding, Idaho Power believes the modeling of gas-fired generation at Bridger units 1 and 2 is preferable to the modeling of four coal-fired units at Bridger, which would be immediately outdated as of the day rates go into effect.

Q. Are there any additional adjustments that need to be made to properly determine the 2023 Test Year?

A. Yes. It is necessary for the Company to make additional annualizing and known and measurable adjustments.

Q. Which other annualizing adjustments were made under your direction to the 2023 Test Year?

A. I instructed Ms. Noe to make annualizing adjustments to certain expense and rate base items to reflect them as though they have been in existence for the entire 2023 Test Year; that is, at year-end 2023 levels. These include operating payroll, depreciation expense and reserve, and plant placed in service during 2023 in excess of $8 million with the associated estimated property taxes and insurance premiums. Such adjustments are appropriate to reflect conditions that will be in effect at the time rates are placed in effect. Ms. Noe provides additional detail regarding the annualizing adjustments in her testimony.

Q. Has an exhibit been prepared that details each of the adjustments that were made to move from the 2022 Actuals to the 2023 Test Year?

A. Yes. Ms. Noe's Exhibit No. 34 summarizes the adjustments that were made to each FERC Account to: 1) move from the 2022 Actuals to the 2022 Base, 2) move from the 2022 Base to the 2023 Unadjusted Test Year, and 3) move from the 2023 Unadjusted Test Year to the 2023 Test Year.

Q. How did you direct Ms. Noe to reflect the costs and revenues associated with Black Mesa and the Micron Special Contract?

A. Due to the offsetting nature of these costs and revenues, I directed Ms. Noe to exclude both components from the Idaho jurisdictional revenue requirement.

Q. Did you direct Ms. Noe to make any additional adjustments prior to quantifying the Company’s requested revenue requirement in this case?

A. Yes. As previously discussed, in order to determine an accurate revenue requirement change, Ms. Noe had to first include the currently authorized recovery for non-fuel coal-related costs. I directed Ms. Noe to include the requested Bridger and Valmy levelized revenue requirements as separate lines in the JSS. Further, as discussed in Mr. Tatum’s testimony, Idaho Power is proposing to offset the revenue requirement increase stemming from the battery projects to be installed in 2023 through the acceleration of accumulated deferred investment tax credits (“ADITC”). I directed Ms. Noe to incorporate this proposed rate mitigation into the quantification of the Company’s request as well. Lastly, I directed Ms. Noe to reflect two transfer adjustments in the body of the JSS.

Q. What is meant by transfer adjustment?

A. Two of the Company’s proposed updates in this case will have corresponding offsetting impacts on other rate mechanisms, thus reducing the net increase to customer bills. The term “transfer adjustment” is in reference to the fact that the recovery of these components of revenue requirement is already reflected in customer rates, and the Company’s request in this case merely reflects the transfer of this recovery to base rates rather than a true increase to customer bills.

Q. What comprises the transfer adjustments?

A. The transfer adjustments are comprised of the aforementioned Rider labor adjustment and an update to PCA-related items.

Q. Please describe the transfer adjustment related to the Rider.

A. The Rider labor adjustment is simply the movement of labor-related costs out of the Rider and into base rates. As discussed by Mr. Tatum, the Company is proposing a corresponding reduction in the Rider percentage, thus resulting in no material impact to customer bills.

Q. What comprises the PCA-related transfer adjustment?

A. The PCA transfer adjustment is comprised of two subcomponents: 1) the reduction to the PCA due to an update to base NPSE, and 2) removal of EIM-related revenue requirement from PCA recovery.

Q. How will the PCA be reduced as a result of the base NPSE update?

A. A primary component of PCA rates contained in Schedule 55 is the difference between base NPSE and the forecast of NPSE for the PCA year. Therefore, when base NPSE are updated— and in this case, increased— the difference between base NPSE and the forecast established in the PCA is reduced, necessitating a reduction in Schedule 55 PCA rates. Consequently, the increase in NPSE proposed to be included in base rates is mostly offset by a corresponding reduction in the PCA rate. The only net impact to customers stems from the difference between full recovery in base rates of base NPSE, as compared to 95 percent recovery of deviations between base NPSE and forecast NPSE for certain accounts through the PCA. Ms. Brady quantifies this component of the PCA transfer adjustment in her testimony.

Q. Please explain the component of the PCA-related transfer adjustment stemming from EIM costs.

A. In accordance with Order No. 33706, which approved Idaho Power's entrance into the EIM, the Company currently collects actual EIM-related costs through the PCA balancing adjustment. Order No. 34100 authorized Idaho

Power to recover its actual EIM-related costs on a backward-looking basis, as benefits in the form of reduced NPSE also flow through the PCA balancing adjustment via actual realized NPSE. This method of cost recovery was intended to capture these costs until they could be included in the Company's base rates as Idaho Power is proposing in this case. Therefore, to recognize that the Company's 2023 Test Year includes EIM-related costs that are currently collected through the balancing adjustment, Idaho Power has included a transfer adjustment in its quantification of the 2023 revenue requirement computation.

Q. What is the total amount of the transfer adjustments reflected in the presentment of the Company's 2023 revenue requirement computation?

A. The three transfer adjustments are listed in the following table on an Idaho jurisdictional basis:

Table 1: Transfer Adjustments by Component

Component	**Amount**
Rider Labor Transfer	$3,474,555
PCA Transfer – EIM	$2,456,681
PCA Transfer – Base Update	$170,912,271
Total	**$176,843,507**

Q. What direction did you provide Ms. Noe with regard to the inclusion of the transfer adjustments?

A. To recognize that these costs are already reflected in customer rates, I directed Ms. Noe to include these transfer adjustments in 2023 Test Year operating revenues.

Q. According to Ms. Noe's analysis using the 2023 Test Year and incorporating the adjustments she made at your direction, what is the Company's revenue requirement on an Idaho jurisdictional basis?

A. Using the 2023 Test Year financial information, Ms. Noe has calculated the Company's revenue requirement to be $1,404.3 million on an Idaho jurisdictional basis. Ms. Noe calculated the Company's annual revenue deficiency, the amount that the test year revenue requirement exceeds the test year retail sales revenue, to be $111.3 million on an Idaho jurisdictional basis, which would result in an overall average increase to customer rates of 8.61 percent.

Q. Is it appropriate for the Commission to determine the Company's Idaho-jurisdictional revenue requirement to be $1,404.3 million, its revenue deficiency to be $111.3 million, and therefore, approve an overall 8.61 percent increase to customer rates?

A. Yes. The $1,404.3 million figure is a reasonable determination of the Company's annual Idaho-jurisdictional revenue requirement. The $111.3 million quantification of revenue deficiency is also reasonable. It is in the best interest of the Company and its customers for the Commission to approve a rate increase to provide an 8.61 percent increase to the Company's Idaho jurisdictional revenues.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF MATTHEW T. LARKIN

I, Matthew T. Larkin, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Matthew T. Larkin. I am employed by Idaho Power Company as the Revenue Requirement Senior Manager.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 25 through 26 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: ____________________
MATTHEW T. LARKIN