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

KELLEY NOE

Q. Please state your name and business address.
A. My name is Kelley Noe. My business address is 1221 West Idaho Street, Boise, Idaho.
Q. By whom are you employed and in what capacity?
A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Regulatory Consultant.
Q. Please describe your educational background.
A. In May of 2004, I received a Bachelor of Business Administration in Finance from Boise State University. I have also attended electric utility ratemaking courses, including "The Basics: Practical Regulatory Training for the Electric Industry," a course offered through New Mexico State University's Center for Public Utilities as well as "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Electric Utilities Consultants, Inc.
Q. Please describe your business experience with Idaho Power Company.
A. In September 2006, I accepted a position at Idaho Power as a Financial Analyst in the Finance Department. My primary duties included performing credit reviews on current and prospective transmission customers as well as providing the financial support for Grid Operations, Planning, and Operations Analysis and Development. In October 2010, I accepted a Regulatory Analyst II position

within the Regulatory Affairs department of the Company. In 2015, I was promoted to Senior Regulatory Analyst, and in 2020 was promoted to my current position, Regulatory Consultant. My duties as a Regulatory Consultant include gathering, analyzing, and coordinating data from various departments throughout the Company required for preparing jurisdictional separation studies, developing complex cost-related studies, and the analysis of strategic regulatory issues.

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

A. I am sponsoring testimony to summarize the development of the system revenue requirement for purposes of forecasting the Company's rate base, revenues, and expenses for the 2023 Test Year, as well as, quantifying the Idaho Jurisdictional Revenue Requirement resulting from the Jurisdictional Separation Study ("JSS") for the twelve months ending December 31, 2023.

Q. Have you prepared exhibits for this proceeding?

A. Yes. I am offering the following exhibits:

1. Exhibit No. 31, Major Plant Additions Annualized for 2023

2. Exhibit No. 32, Depreciation & Amortization Annualizing Adjustments

3. Exhibit No. 33, Summary of Payroll-Related

Annualizing Adjustments

4. Exhibit No. 34, Development of System Revenue Requirement

5. Exhibit No. 35, Jurisdictional Separation Study - Idaho Revenue Requirement.

Development of the System Revenue Requirement

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

A. Yes. As described in the Direct Testimonies and Exhibits of Company Witnesses Ms. Paula Jeppsen and Mr. Matthew Larkin, the development of the 2023 Test Year begins with 2022 actual financial data ("2022 Actuals"). The 2022 Actuals were adjusted to reflect currently approved ratemaking adjustments and amounts previously deferred related to wildfire mitigation ("WFM") in 2022 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"). After the 2023 Unadjusted Test Year figures were compiled, they were provided to me as the starting point for the development of the Company's total 2023 Test Year figures used in this filing.

Q. Were any additional adjustments made to the 2023 Unadjusted Test Year amounts to reach the Company's total 2023 Test Year figures?

A. Yes. Exhibits 31 through 33 illustrate the annualizing adjustments used to develop the total 2023 rate base and net income figures used in the Company's 2023 Test Year.

Q. Please describe the role of annualizing adjustments in this filing.

A. At Mr. Larkin's direction, I performed several annualizing adjustments to amounts that are incurred within the Test Year but need to be reflected for the full year on an ongoing basis.

Q. Please describe the annualizing adjustments made for "Major Plant Additions."

A. "Major Plant Additions," illustrated in Exhibit No. 31, are defined as those investments exceeding $8 million that will close to the Company's electric plant-in-service accounts during the calendar year 2023. A month-by-month forecast of 2023 electric plant-in-service and the 13-month average balances provided by Ms. Jeppsen form the beginning point for the analysis. Annualizing adjustments are applied only to the 2023 plant additions that qualify as Major Plant Additions to establish the amount of investment that would have been recorded had the plant been in service throughout the entire year.

As reflected in Exhibit No. 31, the difference between what had been forecast for these investments in the initial analysis compared to the annualized forecast, as illustrated in column 8 – Net Annualizing Adjustments, is the $161,434,512 annualizing adjustment for the Company's electric plant-in-service investment in this filing. Additional annualizing adjustments associated with Major Plant Additions include $498,233 in property taxes (column 11 – Annual Composite Property Tax) and $75,269 in property insurance (column 13 – Annual Insurance Expense). Because none of the Major Plant Additions were attributable to load growth not already accounted for within the load forecast (see Summary on Exhibit No. 31), an imputed revenue adjustment was not required.

Q. How did you determine the Depreciation & Amortization Annualizing Adjustments?

A. Depreciation and amortization expenses presented in Exhibit No. 32 are forecast on a month-by-month basis during 2023 and summarized in the column entitled "Forecasted Depreciation Expense" (column 4). The expenses for December 2023 are multiplied by twelve to calculate the "Annualized Depreciation Expense" (column 3). The difference between these two columns equals the "Annualizing Adjustment" (column 5) of $8,884,245 depreciation expense and $95,740 amortization expense. Adjustments of $4,442,123 to Accumulated Depreciation and $47,870 to Accumulated Amortization, illustrated as the

"Reserve Adjustment" (column 6), are conventionally computed as half the expense amounts.

Q. Were there any additional labor-related annualizing adjustments?

A. Yes. As set forth in Exhibit No. 33, Summary of Payroll-Related Annualizing Adjustments, there are two additional labor-related annualizing adjustments in this filing totaling $9,561,383.

The first adjustment utilizes 2022 actual labor data as a proxy to annualize 2023 payroll and reflects an entire year of expense at that year-end level. Because the method applied to forecast the 2023 Operations and Maintenance ("O&M") labor expense (detailed in the Direct Testimony of Mr. Larkin) provided only a forecast of the annual 2023 O&M labor expense, a December labor expense amount from which a conventional annualizing labor adjustment could be calculated was not known. Therefore, an annualizing adjustment based upon actual 2022 labor was calculated and used as a proxy to adjust the O&M labor total for the 2023 Test Year. After applying the Company's O&M and benefit loading percentages, the annualizing adjustment is $3,683,272.

The second adjustment of $5,878,111 reflects the projected 2024 salary structure adjustment of 3 percent. This adjustment was applied to the annualized 2023 payroll and has been adjusted by the Company's O&M and benefit loading percentages.

Q. How is Exhibit No. 34, Development of System Revenue Requirement organized?

A. Exhibit No. 34 provides the development of the adjusted total electric system rate base and net income for the test year ending December 31, 2023.

The first set of data, displayed in column 3 "2022 Actual", is the unadjusted 2022 actual results of operations provided by Ms. Jeppsen. The adjustments proposed by the Company for purposes of developing the 2023 adjusted total electric system combined rate base and net income are shown in columns 4 ("2022 Actual Adjustments"), 6 ("Forecast Adjustments"), and 8 ("Annualizing Adjustment"), with the total system adjusted test year rate base, expenses, and revenues summarized in column 9. The proposed adjustments and resulting base amounts are set forth in columns 4 through 8 and result in the 2023 test year data set in column 9, described more fully as follows:

(1) Column 4, titled "2022 Actual Adjustments", was provided by Ms. Jeppsen and Company Witness Ms. Jessica Brady. It reflects currently approved regulatory adjustments that should be applied to the 2022 actual results prior to applying methods to adjust to 2023 levels, as well as adjustments to reflect WFM related expenses

deferred in 2022 thus resetting 2022 actual WFM-related O&M to what it would have been absent the deferral;

(2) Column 5, titled "2022 Base" is the adjusted base to which the methods to create a 2023 test year were applied;

(3) Column 6, titled "Forecast Adjustments", reflects the results of the various methods from the Forecast Methodology Manual sponsored by Mr. Larkin and detailed in his testimony, that were used to adjust totals from the 2022 Base to a 2023 Unadjusted Test Year.

(4) Column 7, titled "2023 Unadjusted Test Year", includes the resulting dataset once the standard regulatory adjustments and various methods were applied;

(5) Column 8, titled "Annualizing Adjustment", includes standard annualizing adjustments, to reflect changes that occur within the test year, but need to be incorporated for the full year on an ongoing basis. All annualizing adjustments included in this filing were discussed earlier in my testimony.

(6) Column 9, titled "2023 Test Year", is the resulting dataset for the 2023 test year (twelve months ending December 31, 2023).

Q. How did you develop the total combined rate base for the 2023 Test Year?

A. Page two of Exhibit No. 34 summarizes the development of rate base components for the 2023 Test Year. The total combined rate base, based on actual, unadjusted 2022 results was $3,870,331,388 (column 3, line 67). After adjustments, the total combined rate base for the 2023 Test Year increases to $4,092,522,974 (column 9, line 67).

Q. Have you prepared any exhibits that detail the total system net income?

A. Yes. Page two of Exhibit No. 34 also includes the development of the total system net income for the twelve months ending December 31, 2023. Operating revenues are summarized on line 73. Total operating expenses are summarized on line 84.

Idaho Jurisdictional Revenue Requirement

Q. Have you prepared an exhibit that sets forth the Idaho jurisdictional revenue deficiency?

A. Yes. I prepared Exhibit No. 35 titled "Jurisdictional Separation Study – Idaho Revenue Requirement" consisting of 36 pages.

Q. Please describe what is included in the Jurisdictional Separation Study report.

A. Exhibit No. 35 is the complete Jurisdictional Separation Study report detailing the allocation of each component of rate base, operating revenues, and expenses by Federal Energy Regulatory Commission ("FERC") account resulting in the Idaho jurisdictional revenue deficiency.

The JSS is organized as follows:

- Summary of Results
- Table 1 - Electric Plant in Service;
- Table 2 - Accumulated Provision for Depreciation (and Amortization);
- Table 3 - Additions & Deductions to Rate Base;
- Table 4 - Operating Revenues;
- Table 5 - Operation & Maintenance Expenses;
- Table 6 - Depreciation & Amortization Expense;
- Table 7 - Taxes Other Than Income Taxes;
- Table 8 - Regulatory Debits & Credits;
- Table 9 - Income Taxes;
- Table 10 - Calculation of Federal Income Tax;
- Table 11 – Oregon State Income Tax;
- Table 12 – Idaho State Income Tax and Other State Income Tax;
- Table 13 - Development of Labor Related Allocator;
- Table 14 - Allocation Factors;
- Table 15 - Allocation Factors-Ratios.

Q. Please discuss the methodology used to jurisdictionally separate costs in the preparation of this study.

A. A three-step process was used to separate costs among jurisdictions. The three steps are functionalization, classification, and allocation of costs. In all three steps, recognition was given to the way in which costs are incurred by relating these costs to utility operations.

Q. Would you please briefly explain what each of the three steps (functionalization, classification, and allocation) entails?

A. Functionalized costs are identified with utility operating functions such as generation, transmission, and distribution. Individual plant items are examined and, where possible, the associated investment costs are assigned to one or more operating functions. Classification groups the functionalized costs into three categories: demand-related, energy-related, and customer-related.

Once the Company's total system costs are classified and assigned to the appropriate function, they are allocated among jurisdictions.

The process of allocation is one of apportioning the total system cost among jurisdictions by introducing allocation factors into the process. An allocation factor is an array of numbers which specifies the jurisdictional value as a share or percent of the total system quantity. For example, in the case of energy-related costs, the allocation factor is annual jurisdictional energy use, adjusted for losses, divided by the total system energy use.

Once individual accounts have been allocated to the various jurisdictions, it is possible to summarize these into total utility rate base and net income by jurisdiction. The results are stated in a summary form to measure adequacy of revenues for the jurisdiction under consideration. The measure of adequacy is typically the rate of return earned on rate base, which is compared to the requested rate of return.

Q. Is the methodology used to separate costs by jurisdiction and calculate the Idaho jurisdictional revenue requirement in the present case primarily the same methodology utilized in the Company's last general rate case, Case No. IPC-E-11-08?

A. Yes.

Q. How have the various functional plant and cost items been allocated?

A. The average of the twelve monthly coincident peak demands was used to allocate the demand-related costs. This allocation method has been used by the Company for at least two decades in all of its filings requiring a jurisdictional separation study. This allocation method was adopted by this Commission and also accepted by the Public Utility Commission of Oregon. The demand-related allocation factors used in the study are designated as D10, D11, D12 and D60. The respective values used in these demand allocation factors are shown at line numbers 1048 through 1051 of Exhibit No. 35.

Q. How were the energy-related expenses allocated among jurisdictions?

A. Energy-related expenses were allocated based on normalized jurisdictional kilowatt-hour sales and adjusted for losses to establish energy requirements at the generation level. The energy-related allocation factors used in the study are designated as E10 and E99. The respective values used in these energy allocation factors are shown on lines 1054 and 1055 of Exhibit No. 35.

Q. What was the method by which you allocated customer-related costs?

A. The principal customer-related expenses which required allocation, were meter reading (FERC Account 902) and customer accounting and billing (FERC Account 903). These accounts were allocated based upon a review of actual costs to read meters and prepare monthly bills or statements.

Q. What method was used to allocate certain labor-related administrative and general expenses?

A. In accordance with FERC-approved procedures, administrative and general expenses were allocated in accordance with functionalized wages and salaries. These labor-related allocation factors are shown on lines 848 through 1043 of Exhibit No. 35.

Q. Please describe the derivation of the 2023 total system allocation factors used in this case.

A. The allocation factors in the 2023 JSS were based on either the 2022 year-end data or 2023 forecast data. The capacity or demand-related allocation factors (D10, D11, D12 and D60) were created using the 2022 demand ratios from the load research analysis applied to the 2023 test year energy. The energy-related allocation factors were the 2023 test year load at generation level (E10) and at customer level (E99). This data is prepared by the Company's Load Research and Forecasting Department and is further described in workpapers filed by Mr. Larkin.

Q. Briefly describe the manner in which you allocated electric plant-in-service as shown in Table 1 of Exhibit No. 35.

A. Both production and transmission plant were allocated to each jurisdiction based on the average of the twelve-monthly coincident peaks. Distribution plant, unless otherwise noted, was directly allocated to Idaho based on 2022 actual jurisdictional data.

Q. Please describe the manner in which you allocated general electric plant-in-service.

A. General plant was allocated on the same basis as the sum of the allocated investments in production, transmission, and distribution plant.

Q. How have you allocated the accumulated provision for depreciation and amortization of other utility plant?

A. Accumulated provision for depreciation and amortization totals, as shown on Table 2 of Exhibit No. 35, were allocated based on the related plant account as allocated in Table 1.

Q. How did you allocate other additions to or deductions from rate base?

A. Table 3 of Exhibit No. 35 details the allocation of all other additions to or deductions from rate base. Deductions from rate base include customer advances for construction that were directly assigned to customers by jurisdiction, and the accumulated deferred income taxes that were allocated by plant, customer advances for construction, and labor. Additions to rate base include: (1) materials and supplies which were functionalized and allocated by the respective plant allocators, (2) fuel inventory that was allocated on the basis of energy, (3) components of Idaho Energy Resources Co. ("IERCo") the Company's fuel subsidiary, which were allocated based on energy, and (4) Commission-ordered deferred investment was either directly assigned to a specific jurisdiction or allocated based on demand.

All rate base items, with the exception of other deferred programs, reflect a 13-month average of ending balances or average of year-end balances.

Q. How did you assign the firm operating revenues to each jurisdiction?

A. Table 4 of Exhibit No. 35 contains the firm operating revenues directly assigned to each jurisdiction for the test year (twelve months ending December 31, 2023). Opportunity sales and financial losses are also credited to each jurisdiction in proportion to generation-level energy use.

Other operating revenues were either allocated among jurisdictions in a manner that offset related allocations of rate base or, where a particular revenue item could be associated with a specific jurisdiction, directly assigned.

Lastly, at the direction of Mr. Larkin I included the transfer adjustments for both the Power Cost Adjustment ("PCA") mechanism and the Energy Efficiency rider labor in this table to more accurately reflect the net impact to customers in the revenue requirement calculation. The Direct Testimony of Mr. Pawel Goralski details the quantification of the revenue transfer from the PCA, and Mr. Larkin details the quantification of the Energy Efficiency rider offset.

Q. How are operation and maintenance expenses allocated to each jurisdiction?

A. The allocation of each O&M expense is detailed on Table 5 of Exhibit No. 35. In general, the basis for each allocation is identifiable with the source code listed on Exhibit No. 35. Demands are identified by a source code beginning with a “D” prefix, energy use is identified by a source code beginning with an “E” prefix, related plant is identified by a line number source code, and customer-weighted allocation factors begin with a “CW” prefix.

Q. In what manner are supervision and engineering expenses treated throughout the allocation of operation and maintenance expenses?

A. For the applicable expense account in each functional group, the labor component was separately allocated in accordance with the detail provided on Table 13 of Exhibit No. 35. The total of allocated labor in each functional group became the basis for the allocation of supervision and engineering expense. Total allocated labor expense served the additional purpose of allocating employee pension and other labor-related taxes and expenses. Table 13 of Exhibit No. 35 details the development of all the labor-related allocation factors used in this study.

Q. How have you allocated depreciation expense and amortization of limited term plant?

A. The allocation of depreciation expense and amortization of limited term plant is set forth in Table 6 of Exhibit No. 35. These expenses were identified by type of production plant or by primary plant account for other functional plant groups and allocated consistent with the related plant account.

Q. How did you approach the allocation of taxes other than income taxes?

A. As set forth in Table 7 of Exhibit No. 35, taxes other than income taxes were treated individually and allocated in a manner consistent with the bases by which the respective taxes are assessed.

Q. How did you address the amortization of regulatory debits and credits?

A. Table 8 of Exhibit No. 35 details the amortization of regulatory debits and credits and were directly assigned to the appropriate jurisdiction.

Q. Does the JSS report detail how deferred income taxes and investment tax credit adjustments were allocated?

A. Yes. The expenses shown on Table 9 of Exhibit No. 35 consist of deferred income taxes and the investment tax credit adjustments, which were allocated based on the Company's plant investment and net income before tax adjustments. State and federal income tax liabilities are also summarized on Table 9. The income taxes shown on Tables 10 through 12 were obtained from the Company's Tax Department.

Q. How were federal and state income taxes, shown on Tables 10 through 12 of Exhibit No. 35, allocated in the JSS?

A. The respective tax bases were developed, and taxes were calculated directly for each jurisdiction. Operating income before taxes represents adjusted operating revenues less all adjusted operating expenses treated heretofore with the exception of deferred income taxes and investment tax credits. Adjusted interest expense was allocated by the combined rate base to develop net operating income before taxes. As discussed earlier in this testimony, subsequent additions to or deductions from the respective tax bases were allocated to each jurisdiction by aligning it with its causation or fundamental association. In this manner, taxable income for each jurisdiction was developed and the appropriate tax rate was applied. Final tax amounts result after the allocation of adjustments and tax credits. All details relating to the calculation of federal, Oregon, Idaho, and other state income taxes are found on Tables 10, 11, and 12.

Q. What is the purpose of Tables 13 through 15 of

Exhibit No. 35?

A. Tables 13 through 15 of Exhibit No. 35 list the principal allocation factors used in the JSS and the respective jurisdictional values for each allocation factor. Table 15 lists the ratios of the principal allocation factors included in Table 14.

Q. How was the Idaho jurisdictional revenue deficiency developed?

A. The summary of JSS results is presented on pages one and two of Exhibit No. 35. The development of the Idaho jurisdictional revenue deficiency is presented in the column entitled "Idaho Retail" on page one of Exhibit No. 35. As discussed further in Mr. Larkin's testimony, due to the approved balancing account mechanisms for recovery of coal-related costs at the Jim Bridger Power Plant ("Bridger") and North Valmy Power Plant ("Valmy"), a true revenue deficiency cannot be computed until the levelized revenue requirement associated with these mechanisms is accounted for in the calculation. While the approved revenue collection is embedded in the Firm Jurisdictional Sales contained on line 9 of the JSS, the corresponding costs were removed from the determination of the Company's non-levelized revenue requirement as described by Mr. Larkin. Therefore, JSS summary information contained on lines 6 through 38 will understate required revenues because it only reflects currently approved revenues related to non-fuel coal recovery, not the corresponding currently approved costs.

Q. How was the Idaho jurisdictional revenue requirement calculated before adjusting for Bridger and Valmy?

A. The pre-adjusted Idaho consolidated operating income of $287,151,546 (line 26) resulted in a return on rate base of 7.34 percent (line 27). Based upon the Company's request for an overall rate of return of 7.702 percent provided by Company Witness Mr. Brian Buckham, the Company's Idaho jurisdictional net income should be $301,346,128, as shown on line 32. The resulting earnings deficiency is $14,194,582, as shown on line 33. Inclusion of Hells Canyon Relicensing Construction Work in Progress allowed in the Company's most recent rate case (Case No. IPC-E-11-08) of $6,537,444, as shown on line 34, increases the earnings deficiency to $20,732,026, as shown on line 35. Once again, as discussed previously, this figure is understated and must be adjusted because it includes Bridger and Valmy coal-related revenue recovery without reflecting the corresponding costs.

Q. What net-to-gross or incremental income tax factor did you use in developing the Idaho jurisdictional revenue deficiency?

A. The composite incremental tax multiplier of 1.347 is the assimilation of the federal effective tax rate, an Idaho composite tax rate, an Oregon composite tax rate, and an additional state composite tax rate. This value, as shown on line 37 of Exhibit No. 35, was provided by the Company's Tax Department and is included in my workpapers.

Q. Why were the Valmy and Bridger revenue requirements added to the Idaho Jurisdictional revenue deficiency calculation contained on lines 40 and 41 of the JSS?

A. To determine the true revenue deficiency, at Mr. Larkin's direction the levelized revenue requirements for Valmy and Bridger were added to the Idaho Jurisdictional revenue requirement calculation on lines 40 and 41, respectively. The addition of these amounts appropriately includes the costs authorized for recovery through these mechanisms to align with the currently approved retail rates embedded in the 2023 Test Year retail revenue forecast. In addition, as discussed in Mr. Larkin's testimony, the Company is requesting recovery of the full annual levelized revenue requirement approved in Case No. IPC-E-21-17 and amortization of previously deferred levelized revenue requirement amount.

Q. Were any other adjustments included in the revenue requirement calculation?

A. Yes, at the direction of Company Witness Mr. Timothy Tatum, I calculated the Idaho jurisdictional revenue requirement of the 120 MW of battery storage that is scheduled to come online in 2023 and included that result as a reduction to the Idaho jurisdictional revenue requirement in an effort to mitigate the increase to customers ("Battery Mitigation") by adding the investment tax credits to the current accumulated deferred investment tax credit ("ADITC") mechanism and adjusting the yearly cap. The impact of this mitigation option is reflected on line 42 of the JSS and is discussed fully in the testimony of Mr. Tatum.

Q. What is the resulting Idaho jurisdictional revenue deficiency including the Battery Mitigation?

A. The result of the Jurisdictional Separation Study, as shown on page one, line 43 of Exhibit No. 35, indicates a total revenue deficiency of $111.3 million for the Idaho retail jurisdiction. This represents a required 8.61 percent increase in normalized Idaho jurisdictional revenues.

Q. Does this conclude your testimony?

A. Yes, it does.

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DECLARATION OF KELLEY NOE

I, Kelley Noe, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Kelley Noe. I am employed by Idaho Power Company as Regulatory Consultant in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 31-35 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibit 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: ____________________
Kelley Noe