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

JESSICA G. BRADY

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

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

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, and "Electric Utility Fundamentals & Insights," an electric utility course offered through the Western Energy Institute.

Q. Please describe your work experience with Idaho Power.

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.

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

A. The purpose of my testimony is to discuss the derivation of the Company's 2023 retail revenue forecast used for the 2023 test year, detail the proposed energy-related test year billing components, present the quantification of 2023 normalized or "base level" net power supply expenses ("2023 Base Level NPSE") and inform the Commission of the necessary reduction to the rates contained in Schedule 55, Power Cost Adjustment ("PCA") resulting from the proposed 2023 Base Level NPSE update.

I. 2023 TEST YEAR RETAIL REVENUE DERIVATION

Q. What methodology was used to determine test year retail revenues?

A. Generally speaking, the Company's retail revenue forecast is derived by applying current base rates to forecasted test year billing components. These billing components are derived by applying historical relationships to the Company's customer and kilowatt-hour ("kWh") sales forecast.

Q. Was the 2023 test year retail sales revenue forecast developed using the same methodology applied in the Company's last general rate case, Case No. IPC-E-11-08 ("2011 Rate Case")?

A. Yes. The 2023 test year retail sales revenue forecast was developed using the same methodology applied in the 2011 Rate Case.

Q. Please describe the customer and kWh sales forecast that serves as the basis for the 2023 test year retail revenue forecast.

A. The 2023 test year customer and kWh sales forecast consists of class customer counts and total kWh sales estimates for each month of the test period. It is prepared by the Company's Load Research and Forecasting Department and is further described in workpapers filed by Company Witness Mr. Matthew Larkin.

Q. How were the 2023 test year kWh sales further segmented into the class-specific energy-related billing components?

A. The first step in deriving energy-related billing components for the test year is to develop factors based on the most current complete calendar year of available historical data, which in this case is 2022. These historical factors represent the percentage of total kWh billed in each tier level of a class's rate structure.

To illustrate, Residential Service customers taking service under Schedule 1 are billed according to a three-tiered structure with seasonal rate differentiation. Using the historical month of June 2022 as an example, actual tiered usage was recorded at the following levels for Schedule 1 customers in the Idaho jurisdiction:

Table 1
2022 Actual Tiered Usage

Table 1 2022 Actual Tiered Usage	
Usage Tier	**June 2022 Schedule 1 Billing Components**
Summer, 0-800 kWh	105,736,225
Summer, 801-2000 kWh	26,415,166
Summer, Over 2000 kWh	3,257,841
Non-Summer, 0-800 kWh	168,424,645
Non-Summer, 801-2000 kWh	42,615,564
Non-Summer, Over 2000 kWh	6,376,771
Total Schedule 1 kWh Usage	352,826,211[1]

Based on the data above, historical factors for Schedule 1 customers for the month of June were calculated as shown in Table 2.

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Table 2

[1] Totals in tables may not tie due to rounding.

Historical Weighting Factors

Table 2 Historical Weighting Factors	
Usage Tier	**June 2022 Schedule 1 Weighting Factors**
Summer, 0-800 kWh	30%
Summer, 801-2000 kWh	7%
Summer, Over 2000 kWh	1%
Non-Summer, 0-800 kWh	48%
Non-Summer, 801-2000 kWh	12%
Non-Summer, Over 2000 kWh	2%
Total Schedule 1	100%

This process is used to develop historical factors for all rate classes with tiered structures. Once a complete set of monthly factors has been developed for each applicable rate class, they are applied to monthly forecast kWh totals to derive the energy-related billing component forecast that aligns with each class's current rate structure. Continuing with the illustration of Schedule 1 customers, Table 3 demonstrates the final step in determining test year energy-related billing components.

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Table 3

Billing Component Forcast

Table 3 Billing Component Forecast

Usage Tier	**Historical June Weighting Factor**	**June 2023 Schedule 1 Billing Component Forecast (kWh)**
Summer, 0-800 kWh	30%	108,107,252
Summer, 801-2000 kWh	7%	27,007,499
Summer, Over 2000 kWh	1%	3,330,895
Non-Summer, 0-800 kWh	48%	172,201,397
Non-Summer, 801-2000 kWh	12%	43,571,175
Non-Summer, Over 2000 kWh	2%	6,519,763
Total	100%	360,737,981

Q. How are demand-related billing components derived based on the kWh sales forecast?

A. The demand-related billing components consist of billing demand and basic load capacity ("BLC") by month for each rate class. Both billing demand and BLC totals are forecasted by applying four-year average load factors to each month in the kWh sales forecast. Historical data from the most currently available four calendar years is used to derive an average load factor by month for each rate class. These average factors are then applied to monthly kWh sales figures to determine total forecasted billing demand and BLC by class for each month of the test period. Once monthly totals have been developed, they are divided into the appropriate tiered rate structure (if applicable) utilizing historical factors in the same manner as kWh charges.

Q. How are customer-related billing components derived based on the customer count forecast?

A. The primary customer-related billing component in the retail revenue forecast is the service charge. Because the customer forecast reflects the expected number of customers under active Utility Service Agreements ("USAs") at the end of each forecast month, forecast values must be converted to reflect the expected number of service charges received throughout the corresponding month. To convert the USA forecast to an expected service charge count, historical factors are developed reflecting the relationship between the number of USAs at the end of each historical month and the number of service charges received during the corresponding month. These factors are then applied to the monthly customer forecast to develop a forecast of expected service charges by rate class for each month of the test year.

Q. How are test year retail revenues calculated once the billing component forecast has been derived?

A. Once the billing components have been forecasted by rate class, the most currently approved base rates are applied to the test year values to derive monthly revenue estimates for each rate class.

Q. Have you prepared any exhibits that detail the calculations that were made to determine the Company's 2023 test year retail revenues?

A. Yes. Exhibit No. 27 provides a summary of forecasted 2023 test year retail revenues, and Exhibit No. 28 details the calculations that were made to determine these revenues. Input data used in the forecast calculations can be found in my workpapers. As can be seen on page 3 of Exhibit No. 27, the Company's 2023 Idaho jurisdictional retail sales revenues are forecast to be $1.12 billion.

Q. How is the portion of Micron Technology's ("Micron") forecast kWh sales that will be met by Black Mesa Solar treated in the 2023 test year retail revenues?

A. As described in the Direct Testimony of Mr. Matthew Larkin, as part of the new Special Contract with Micron, Black Mesa Solar's generation will be paid for completely by Micron. To account for this, the revenue from the portion of Micron's load that will be met by Black Mesa Solar is not included in the 2023 retail revenue forecast. The treatment of the revenue associated with the portion of Micron's load met by Black Mesa Solar is discussed further in the Direct Testimony of Mr. Paul Goralski.

II. 2023 ENERGY-RELATED BILLING COMPONENTS – PROPOSED RATE STRUCTURE

Q. Please describe the energy-related billing components under the Company's proposed rate structure ("proposed billing components").

A. As described in the Direct Testimony of Ms. Connie Aschenbrenner, the Company's proposed rate structure includes modifying the months considered to be "summer" and "non-summer", as well as the time-of-use periods for certain time variant rate classes. The proposed billing components represent the total forecast kWh billed in each tier within each rate class, under the new proposed rate structure.

Q. How were the proposed billing components calculated?

A. The proposed billing components were calculated using the same methodology as the billing components calculated for the derivation of the 2023 test year retail revenues. However, instead of using 2022 billing data to derive historical factors, 2022 kWh usage data, divided into tiers based on the proposed rate structure for each rate class, was used.

Q. How was the 2022 kWh usage data collected and divided into the proposed tiers?

A. The process for collecting 2022 kWh usage data is described in workpapers filed by Mr. Larkin.

Q. Have you prepared an exhibit that details the Company's 2023 proposed billing determinants?

A. Yes. Exhibit No. 29 provides a summary of the 2023 proposed billing determinants.

III. 2023 BASE NET POWER SUPPLY EXPENSES

Q. How is this section of your testimony organized?

A. First, I provide an overview of the Commission-approved method for quantifying base level NPSE. Next, I describe the update to base level NPSE that occurred in 2013 ("2013 Base Level NPSE"). Lastly, I describe the quantification of the Company's 2023 Base Level NPSE.

Q. How has the Commission historically reviewed and approved Idaho Power's quantification of normal base NPSE?

A. Due to the high variability of power supply expenses, the Commission has historically approved a normalized power supply expense value for setting base rates. The Company has utilized the AURORA model to provide the Commission with a snapshot of "normal" expectations for base NPSE for a given test year.

Q. Please define the term “base NPSE” as the Company and Commission have used the term historically.

A. The Company and Commission have historically defined the term “base NPSE” as the sum of fuel expenses (Federal Energy Regulatory Commission [“FERC”] Accounts 501 and 547) and purchased power expenses (FERC Account 555), including purchases from qualifying facilities under the Public Utility Regulatory Policies Act of 1978 (“PURPA”) and power purchase agreements (“PPA”), minus surplus sales revenues (FERC Account 447). The AURORA model is used to quantify base NPSE components related to fuel and surplus sales, while PURPA and PPA expenses are quantified outside of AURORA; however, energy from these projects is modeled as must-take in the AURORA simulation.

Q. Does the Company include any other categories of expense or revenue in the base level NPSE used for PCA computations?

A. Yes. In addition to the expense and revenue categories described above, the base level NPSE included in the Company’s PCA computations also includes financial payments made by Idaho Power to offset transmission losses associated with market purchases (FERC Account 555), third-party transmission expense required to bring market purchases to the Company’s border (FERC Account 565), water for power expense (FERC Account 536), and demand response (“DR”) incentives (FERC Account 555).

Q. Is the Company proposing to include any new categories of expense or revenue in the base level NPSE used for PCA computations?

A. Yes. At the direction of Mr. Larkin, I have included an additional component, FERC Account 447.050, transmission loss revenue, in the 2023 Base Level NPSE. According to the FERC’s Uniform System of Accounts, these amounts are recorded to Account 447.

Q. What does the transmission loss revenue component of Account 447 represent?

A. As further discussed in Mr. Larkin’s testimony, transmission loss revenue in FERC Account 447 reflects revenues received by Idaho Power from third parties to compensate the Company for physically generating electricity to offset losses associated with wheeling energy through Idaho Power’s transmission system.

Q. How does the Company arrive at a “normalized” look at base NPSE for ratemaking purposes?

A. In order to “normalize” base NPSE, the Company uses AURORA to model various water conditions using current loads and current resources. At this time, 37 water conditions have been evaluated to develop an average or normalized NPSE. This general methodology was adopted by the Commission in 1981 and has been used in general rate proceedings ever since.

Q. What is the currently approved base level NPSE amount?

A. The currently approved 2013 Base Level NPSE is $305,684,869. It is comprised of the following components:

Table 4
2013 Bale Level NPSE

Table 4 2013 Base Level NPSE	
95% Accounts (with 95% recovery in PCA)	
Account 501, fuel (coal)	$108,503,180
Account 536, water for power	$2,380,597
Account 547, fuel (gas)	$33,367,563
Account 555, purchased power (non-PURPA)	$62,606,593
Account 565, third-party transmission	$5,455,955
Account 447, surplus sales	($51,735,153)
Net 95% Accounts	$160,578,735
100% Accounts (with 100% recovery in PCA)	
Account 555, purchased power (PURPA)	$133,853,869
Account 555, purchased power (demand response)	$11,252,265
Total	$305,684,869

Q. When was the currently approved base level NPSE established and approved by the Commission?

A. The 2013 Base Level NPSE was established on March 21, 2014, by Order No. 33000 issued in Case No. IPC-E-13-20.

Q. Since the establishment of the 2013 Base Level NPSE, has the Company made any modifications to the AURORA model that was used to develop the 2023 Base Level NPSE?

A. Yes. In order to quantify the 2023 Base Level NPSE, the Company utilized a new AURORA version and database, which reflects updated inputs for the entire Western Electricity Coordinating Counsel ("WECC") footprint. This database was also used in the development of the Company's 2021 Integrated Resource Plan ("IRP"), which was acknowledged by the Commission on November 18, 2022, in Order No. 35603 issued in Case No. IPC-E-21-43. The Company also updated the database to include resource changes, current fuel prices, heat rates, forced outage rates, maintenance schedules, and plant capacities.

Q. Were any adjustments made to the resources included in the 2023 AURORA Model?

A. Yes. Idaho Power updated expected generation from PURPA projects based on current or expected contracts. Additionally, the 2023 AURORA model includes the removal of two resources, Boardman Coal and North Valmy Unit 1, and the addition of six resources. The six resources are listed below.

New Resources included in the 2023 AURORA Model

1. Bridger Gas
2. Jackpot Solar PPA
3. Black Mesa Solar PPA
4. Black Mesa Battery
5. 80-Megawatt ("MW") Grid Battery
6. Demand Response

Q. Please describe the Bridger Gas resource, including how it was modeled for the development of the 2023 Base Level NPSE.

A. The Company's 2021 IRP Action Plan includes the conversion of Bridger units 1 and 2 from coal to natural gas by summer 2024. As discussed further in Mr. Larkin's testimony, I was directed to model Bridger units 1 and 2 as natural gas units online for the entire 2023 test year in order to more closely align 2023 Base Level NPSE with the time period in which rates will take effect.

Q. How were Jackpot Solar and Black Mesa Solar modeled for the development of the 2023 Base Level NPSE?

A. Jackpot Solar, which came online December 2022, is a 120-MW alternating current solar photovoltaic generation facility. It is a 20-year PPA with Jackpot Holdings, LLC.

Black Mesa Solar is a 40-MW alternating current solar photovoltaic facility that is scheduled to come online June 2023. As described previously in my testimony, and further detailed in Mr. Larkin's testimony, Black Mesa Solar is a PPA that was negotiated in conjunction with a new Special Contract with Micron Technology. The Micron 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 Black Mesa Solar will be connected to the Company’s system and will not serve Micron directly, Micron will pay for 100 percent of the output through its Special Contract. As a result, the cost of the PPA is excluded from the 2023 Base Level NPSE.

The Company modeled both Jackpot Solar and Black Mesa Solar’s generation in AURORA by applying the projects’ forecast hourly shape to the monthly forecasted generation amounts. In addition, Black Mesa Solar was modeled as an annualized online resource for the entire test year, in line with the Company’s typical practice for resources expected to come online during the test year.

Q. How were the two new battery resources modeled for the development of the 2023 Base Level NPSE?

A. The two new battery resources include a 40-MW battery at Black Mesa Solar and an 80-MW grid battery. The Black Mesa Battery is scheduled to come online September 2023 and the 80-MW grid battery is scheduled to come online June 2023. Similar to Bridger Gas and Black Mesa Solar, both batteries were modeled as annualized online resources for the entire test year.

The 80-MW grid battery is modeled to be charged from the entire grid, while the Black Mesa Battery is modeled to only be charged from Black Mesa Solar.

Q. How was demand response modeled for the development of the 2023 Base Level NPSE?

A. 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.

Q. Have there been any changes to the way PURPA is modeled compared to the way it was modeled in the 2013 Base Level NPSE?

A. Yes. In the 2013 normalized NPSE determinations, the Company segmented PURPA generation into two categories, "PURPA Wind" and all "other PURPA". PURPA Wind was modeled by applying the 2012 hourly actual historical PURPA Wind generation shape to the monthly forecasted generation amounts. All other PURPA resources were modeled on a monthly basis.

For the 2023 Base Level NPSE, the Company segmented PURPA into three categories, "PURPA Wind", "PURPA Solar", and all "other PURPA". PURPA Wind was modeled by applying a 5-year average (2018 – 2022) hourly actual generation shape to the total nameplate capacity of the combined PURPA wind projects. PURPA Solar was modeled by applying the 2022 actual hourly shape to the total monthly forecasted generation amounts. All other PURPA resources were modeled on a monthly basis, as hourly fluctuations do not occur to as great an extent for those resource types. The Company views the modification to be an improvement that more accurately reflects the variable nature of solar into the hourly dispatch modeling in AURORA.

Q. What other AURORA inputs were modified for the development of the 2023 Base Level NPSE?

A. The Company included annualized forecast generation from its Oregon Community Solar Program, which is scheduled to come online November 2023. In addition, the Company included 11 MW of distribution-connected battery storage.

Q. Have you prepared an exhibit that presents the normalization of variable power supply expenses consistent with the changes you have described in your testimony?

A. Yes. Exhibit No. 30 shows the results containing the 37-year average variable power supply generation sources and expenses.

Q. Please summarize the sources and disposition of energy shown on Exhibit No. 30.

A. Hydro generation supplies 8.3 million megawatt-hours ("MWh"), approximately 47 percent (8.3 million MWh / 17.8 million MWh = 47 percent) of the generation mix. Thermal generation supplies 4.1 million MWh (Bridger Coal 1.8, Bridger Gas 0.1, Valmy 0.2, Langley Gulch 1.7, Danskin 0.2, Bennett Mountain 0.1), approximately 23 percent (4.1 million MWh / 17.8 million MWh = 23 percent) of the generation mix. Purchases of power are made up of short-term and long-term market purchases, as well as PURPA generation. Short-term market purchases supply 1.4 million MWh, approximately 8 percent of the generation mix. Long-term market purchases, or PPAs, supply 0.96 million MWh, approximately 5 percent of the generation mix. PURPA purchases reflect normalized and annualized generation levels and account for 3.0 million MWh, approximately 17 percent of the generation mix. Total purchases amount to 5.3 million MWh (1.4 million MWh + 0.96 million MWh + 3.0 million MWh = 5.3 million MWh) or approximately 30 percent of the generation mix. Of the 17.8 million MWh generated by the system, 17.0 million MWh are utilized for system loads while 0.8 million MWh are sold as surplus sales.

Q. Please summarize the expenses associated with each resource shown on Exhibit No. 30.

A. Hydro generation has no assumed fuel expense. Coal expenses of $65.5 million are comprised of Bridger at $57.1 million and Valmy at $8.4 million. Gas expenses of $119.7 million are comprised of Langley Gulch at $78.7 million, Bridger Gas at $6.1 million, Danskin at $13.8 million, and Bennett Mountain at $6.8 million. The fixed capacity charge for gas transportation for all of the gas plants is $14.3 million. Purchased power expenses (*including transmission losses, excluding PURPA*) amount to $99.5 million, and surplus sales revenue (*including transmission losses)* is ($29.0) million. Transmission losses will be discussed in more detail later in my testimony.

Q. How have natural gas prices changed between the time of quantification of the 2013 Base Level NPSE and the 2023 Base Level NPSE quantification?

A. For the 2013 Base Level NPSE, natural gas prices were assumed to be $3.62 per million British thermal units ("MMBtu") for Henry Hub and $3.68 per MMBtu for natural gas delivered to the Company's plants. For the 2023 Base Level NPSE, they are forecasted to be $3.36 per MMBtu for Henry Hub, $4.28 per MMBtu for natural gas delivered to Bridger, and $4.70 per MMBtu for natural gas delivered to Langley, Bennett Mountain, and Danskin.

Q. In general, how has base level NPSE and generation changed from 2013 to 2023?

A. As described earlier in my testimony, since 2013 there have been several changes to Idaho Power's resource mix. These changes were incorporated into the 2023 AURORA model and are reflected in the calculated 2023 Base Level NPSE.

Due to the decrease in coal capacity from the removal of Boardman and North Valmy Unit 1, as well as the conversion of Bridger units 1 and 2 to natural gas, expenses related to coal generation have decreased 40 percent from 2013. In addition, due to the increased reliance on natural gas generation and increase in natural gas price, expenses related to natural gas generation have increased 259 percent.

Next, Non-PUPRA purchased power expense has increased 59 percent since 2013. This is a result of the addition of the Jackpot Solar PPA, as well as the increase in AURORA calculated market purchase volumes and market prices. PURPA expense has increased 60 percent since 2013 as a result of increased PURPA generation and updated PURPA contract values.

Lastly, surplus sales revenue has decreased 44 percent from 2013. As a result of the increase in system load, decrease in coal capacity, and increase in natural gas prices, there are fewer opportunities to make economic off-system sales in the 2023 test year.

Q. How are transmission losses on market purchases (FERC Account 555) accounted for within the Company's calculation of 2023 Base NPSE?

A. Within the AURORA model, transmission losses are incorporated into the market price paid by the purchasing entity. In other words, the purchase price on all short-term market purchases is grossed up to account for transmission losses. As a result, the non-PURPA purchased power expenses of $99.5 million included in FERC Account 555 include both purchased power and transmission losses on purchased power.

Q. Does the Company propose to update the base level NPSE accounts that are not calculated by AURORA, or partially calculated by AURORA, as part of this request?

A. Yes. The Company's proposal reflects 2023 test year amounts for the below FERC Accounts.

447.050	Transmission Loss Revenue
565	Third-Party Transmission Expense
536.003	Water for Power
555	Demand Response

Q. How did the Company determine the 2023 Base Level amount for FERC Account 447.050, Transmission Loss Revenue?

A. FERC Account 447.050, Transmission Loss Revenue, was forecasted by multiplying Idaho Power's average hourly marginal price, as calculated by AURORA, by 36 average MW, which is the assumed average MW generated in each hour to serve third-party transmission losses.

Q. How did the Company determine the average hourly MW generated to serve third-party transmission losses?

A. The 36 MW was provided by the Load Research and Forecasting Department and is further described in the workpapers filed by Mr. Larkin.

Q. How did the Company determine the 2023 Base Level amount for FERC Account 565, Third-Party Transmission Expense?

A. The 2023 test year amount for FERC Account 565, Third-Party Transmission Expense, of $10.3 million was calculated by multiplying the Company's historical 3-year average wheeling rate, based on total wheeling expenses and volumes reported in the FERC Form 1, by the AURORA calculated market purchase volumes. Information used in this calculation can be found in my workpapers.

Q. How did the Company determine the 2023 Base Level amounts for FERC Account 536.003, Water for Power and FERC Account 555, Demand Response?

A. FERC Account 536.003, Water for Power, is forecast at 0 for the 2023 test year. Idaho Power did not have water lease expense amounts in 2022 and does not anticipate any for the 2023 test year.

FERC Account 555, Demand Response, was forecast for the 2023 test year based on Idaho-jurisdictionalized forecast costs associated with projected participation in the three programs.

Q. Have you quantified the 2023 Base Level NPSE amounts?

A. Yes. The 2023 Base Level NPSE amounts as proposed by the Company for Commission-approval are as follows:

Table 5
2023 Base Level NPSE

Table 5 2023 Base Level NPSE	
95% Accounts (with 95% recovery in PCA)	
Account 501, fuel (coal)	$65,523,000
Account 536, water for power	$0
Account 547, fuel (gas)	$119,653,675
Account 555, purchased power (non-PURPA)	$99,465,021
Account 565, third-party transmission	$10,263,139
Account 447, surplus sales	($29,035,180)
Net 95% Accounts	$265,869,655
100% Accounts (with 100% recovery in PCA)	
Account 555, purchased power (PURPA)	$214,448,755
Account 555, purchased power (demand response)	$10,240,003
Total	$490,558,413

Q. How do these 2023 Base Level NPSE amounts compare with the 2013 Base Level NPSE amounts?

A. The 2023 Base Level NPSE total is $490,558,413, an increase of $184,873,544 from the 2013 Base Level NPSE of $305,684,869.

Q. Is Idaho Power proposing to update Schedule 55, Power Cost Adjustment, with this filing?

A. Yes. As discussed in Mr. Larkin's testimony, the update in base NPSE will result in a reduction in the variance between base and forecast NPSE embedded in current PCA rates. Therefore, Idaho Power has calculated an updated PCA rate that incorporates the proposed 2023 Base Level NPSE. If approved as filed, the Company's 2023 Base Level NPSE would result in a reduction in PCA revenue collection of $171,516,689 using the June 2023 through May 2024 PCA year. Applying this rate change to 2023 test year sales results in the $170,912,271 detailed in Mr. Larkin's testimony – the only difference due to differing sales between the June 2023 through May 2024 time period and the January 2023 through December 2023 time period. This comprises the majority of the PCA-related transfer adjustment discussed in Mr. Larkin's testimony. The calculations made to determine the updated PCA forecast rate, as well as the decrease in PCA revenue collection as a result of the 2023 Base Level NPSE update are provided in my workpapers.

Q. Have you prepared a revised Schedule 55 that includes the updated PCA rate?

A. Yes. Attachment 1 to Idaho Power's Application filed concurrently herewith is a revised Schedule 55 and includes the proposed PCA rates in clean and legislative formats.

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

A. Yes, it does.

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DECLARATION OF JESSICA G. BRADY

I, Jessica G. Brady, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Jessica G. Brady. I am employed by Idaho Power Company as a Regulatory Analyst in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 27 through 30 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: Jessica Brady
JESSICA G. BRADY