BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

|  |  |  |
| --- | --- | --- |
| IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (“PCA”) RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2023, THROUGH MAY 31, 2024. | ))))))) | CASE NO. IPC-E-23-12 |

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 of 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.

A. In September 2021, I was hired as a Regulatory Analyst in Idaho Power’s Regulatory Affairs Department. As a Regulatory Analyst, I provide support for the Company’s regulatory activities, including compliance reporting, financial analysis, and the development of revenue forecasts for regulatory filings. I am also responsible for the Company’s power cost filings in both Idaho and Oregon.

Prior to Idaho Power, I worked for five years at Clearwater Analytics, a provider of investment accounting and reporting software. I held various roles at Clearwater Analytics but was primarily focused on customer success and relationship management. I gained a breadth of knowledge in investments and the use of proprietary software to streamline the operations of a company’s finance and accounting teams. I spent my last year at Clearwater developing a training program focused on providing new hires with the technical skills to be successful in an operations role.

Q. What is the Company requesting in this case?

A. The Company is requesting approval of its 2023-2024 Power Cost Adjustment (“PCA”) rates to become effective June 1, 2023. If approved, the 2023-2024 PCA

will result in an increase in total billed revenue of approximately $200.2 million, or 14.68 percent.

Q. How is your testimony organized?

A. My testimony consists of four sections. In the first section, I provide an overview of the PCA. In the second section, I detail the 2023-2024 PCA amount in comparison to last year’s PCA amount, identify and discuss the main factors contributing to this change, and present the quantification of the 2023-2024 PCA rates to become effective June 1, 2023. In the third section, I discuss the additional PCA component related to revenue sharing. In the final section, I detail the net customer impact of the 2023-2024 PCA rates if approved as filed.

**I. PCA OVERVIEW**

Q. What is the purpose of the PCA?

A. The PCA is a rate mechanism that quantifies and tracks annual differences between actual Net Power Supply Expenses (“NPSE”) and the normalized or “base level” of NPSE recovered in the Company’s base rates, resulting in a credit or surcharge that is updated annually on June 1. The PCA mechanism uses a 12-month test period of April through March (“PCA Year”) and includes a forecast component and a Balancing Adjustment, formerly referred to as the “true-up” and the “true-up of the true-up”. The forecast component represents the difference between the Company’s NPSE forecast from the March Operating Plan and base level NPSE recovered in the Company’s base rates. The Balancing Adjustment includes a backward-looking tracking of differences between the prior PCA Year’s forecast and actual NPSE incurred by the Company, and also tracks the collection of the prior year’s Balancing Adjustment.

Q. How does the PCA mechanism function?

A. With the exception of Public Utility Regulatory Policies Act of 1978 (“PURPA”) expenses and demand response incentive payments, the PCA allows the Company to pass through to customers 95 percent of the annual differences in actual NPSE as compared with base level NPSE, whether positive or negative. With respect to PURPA expenses and demand response incentive payments, as actual annual expenses deviate from base level NPSE, the Company is allowed to pass 100 percent of the difference for recovery or credit through the PCA. The PCA is also the rate mechanism used by the Company to provide customer benefits resulting from the revenue sharing mechanism approved by the Commission in Order No. 34071.

Q. Does the revenue collected from customers through the annual PCA rate contribute toward the Company’s earnings?

A. No. The PCA mechanism provides for the annual collection or refund of net power supply cost differences between actual costs incurred by the Company and the base level NPSE component of base rates. Aside from the 95 percent to 5 percent sharing component I just described, the PCA provides for a one-for-one collection or refund of actual net power supply expenses incurred, or to be incurred, to provide safe, reliable electric service to customers.

Q. What are the components of the PCA base level NPSE?

A. The PCA base level NPSE includes the following Federal Energy Regulatory Commission (“FERC”) accounts: Account 501, Fuel (coal); Account 536, Water for Power; Account 547, Fuel (gas); Account 555, Purchased Power; Account 565, Transmission of Electricity by Others; and Account 447, Sales for Resale (typically referred to as surplus sales).

The PCA base level expense component for FERC Account 555 includes costs of both PURPA and non-PURPA (market) purchases. Per Order No. 32426, the Company adjusts FERC Account 555 to also include demand response incentive payments that the Company provides to customers who participate in any of its three demand response programs.

**II. 2023-2024 PCA**

Q. What is the total PCA collection that would result under the 2023-2024 PCA rates proposed by the Company in this case?

A. The 2023-2024 PCA rates would result in total PCA collection of $408.2 million. This represents an increase in total billed revenue of $200.2 million for the upcoming year, an increase of 14.68 percent.

 Q. Have you prepared a table that details the $200.2 million revenue impact by component?

A. Yes. Table 1 presents a separation of the $200.2 million increase into each component included in the Company’s proposed rates.

|  |  |
| --- | --- |
| **Table 1** | **Revenue Impact by Component** |
|   |  |  |  |   |
| **Line No.** | **Rate Component** | **2022-2023 PCA** | **2023-2024 PCA** | **Difference** |
| 1 | PCA Forecast |  $ 169,966,873  | $ 218,005,217 | $ 48,038,344 |
| 2 | PCA Balancing Adjustment |  $ 38,583,273  |  $ 190,208,504  |  $ 151,625,231 |
| 3 | PCA Total |  $ 208,550,146  | $ 408,213,721 | $ 199,663,575 |
| 4 | Revenue Sharing |  $ (568,435) |  $ 0  |  $ 568,435  |
| 5 | **Total Revenue Impact** |  **$ 207,981,710**  | **$ 408,213,721** |  **$ 200,232,011** |

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

A. The increase in this year’s PCA is driven by an increase in both the forecast component and the Balancing Adjustment. The increase in this year’s forecast component is attributed primarily to higher forecast market energy and natural gas prices, combined with a limited coal supply.

As can be seen on Table 1, the Balancing Adjustment accounts for over 75 percent of the overall PCA revenue change, indicating that last year’s actual power costs were greater than forecast. Similar to the forecast component, the increase in the Balancing Adjustment is largely attributed to high natural gas and market energy prices during the 2022-2023 PCA Year, combined with a limited coal

supply. In addition, hydro generation was 9 percent lower than forecast.

The price increases in both the natural gas and energy markets, as well as the limited coal supply, will be discussed in more detail later in this testimony.

**A. PCA Forecast.**

Q. How is the PCA forecast amount determined?

A. As described previously, the PCA forecast component represents the difference between the Company’s forecast of NPSE for the upcoming April – March test year and base level NPSE recovered in the Company’s base rates.

Q. What is the Company’s determination of the system-level difference between currently approved base

level NPSE[[1]](#footnote-1) and the forecast of NPSE for the 2023-2024 PCA Year?

A. The system-level forecast of NPSE for the 2023-2024 PCA Year is $541,499,384, which is $235,814,515 higher than the currently approved base level NPSE of $305,684,869. Table 2 presents the system-level differences between currently approved base level NPSE and the forecast of NPSE for the 2023-2024 PCA Year by FERC account.

|  |  |
| --- | --- |
| **Table 2** | **2023 - 2024 PCA FORECAST (Total System)** |
|   |   |  |  |   |
| **Line No.** | **FERC Account** | **Base NPSE** | **Forecast** | **Difference** |
|   | 95% Sharing Accounts |  |  |   |
| 1 | Account 501, Coal |  $ 108,503,180  |  $ 130,090,026 |  $ 21,586,845  |
| 2 | Account 536, Water for Power |  $ 2,380,597  |  $ 0  |  $ (2,380,597) |
| 3 | Account 547, Other Fuel |  $ 33,367,563  |  $ 134,492,688  |  $ 101,256,077  |
| 4 | Account 555, Purchased Power Non-PURPA |  $ 62,606,593  |  $ 123,485,717 |  $ 60,886,095  |
| 5 | Account 565, 3rd Party Transmission  |  $ 5,455,955  |  $ 7,964,649  |  $ 2,508,694  |
| 6 | Account 447, Surplus Sales |  $ (51,735,153) |  $ (84,191,539) |  $ (32,456,386) |
|   |   |  $ 160,578,735  |  $ 311,979,464  |  $ 151,400,729  |
|   |   |  |  |   |
|   | 100% Sharing Accounts |  |  |   |
| 7 | Account 555, PURPA |  $ 133,853,869  |  $ 218,535,412  |  $ 84,681,543  |
| 8 | Account 555, Demand Response Incentives |  $ 11,252,265  |  $ 10,984,508  |  $ (267,757) |
| 9 | Total |  $ 305,684,869  |  $ 541,499,384  |  $ 235,814,515  |

Q. What is the basis for the forecast of NPSE for the 2023-2024 PCA Year?

A. The forecast of NPSE for the 2023-2024 PCA Year is based on the Company’s March 2023 Operating Plan.

Q. How is the NPSE forecast developed for the Company’s Operating Plan?

A. The Operating Plan is prepared monthly and represents a forecast of the Company’s monthly NPSE for the following 18-month period; however, for the PCA, the Company includes only the 12 months that correspond to the PCA Year. The Operating Plan is developed by simulating the dispatch of the Company’s generation resources for each month, segmented by heavy load and light load hours. The dispatch considers a current forecast of forward market energy prices, available hydro generation, coal and natural gas prices, and any existing hedge transactions. The system load forecast is then analyzed against the resulting monthly heavy load and light load dispatch to determine a monthly load and resource balance. Any identified resource deficiency is assumed to be filled with market energy purchases or natural gas to fuel the Langley Gulch power plant (“Langley Gulch”), based on economics and available generating capacity at Langley Gulch. Economically dispatched generation above the system load forecast represents surplus energy sales. The forecast of monthly NPSE and generation for the 2023-2024 PCA Year, as determined in the Company’s March 2023 Operating Plan, is provided in Exhibit No. 1.

Q. Did the Company make any adjustments to the March 2023 Operating Plan, for purposes of quantifying forecast NPSE for the 2023-2024 PCA Year?

A. Yes. Forecast NPSE in the March 2023 Operating Plan includes the addition of a new power purchase agreement (“PPA”), Black Mesa Solar. For purposes of quantifying forecast NPSE for the 2023-2024 PCA Year for this filing, the Company removed the forecasted expenses associated with Black Mesa Solar, because Micron Technology, Inc. (“Micron”) will be paying for 100 percent of Black Mesa Solar’s generation according to the provisions of a new Energy Sales Agreement (“ESA”)[[2]](#footnote-2) between Idaho Power and Micron.

Q. Please provide more information on the Black Mesa Solar PPA and its treatment in the PCA forecast.

A. Black Mesa Solar is a 40 MW alternating current solar photovoltaic generation facility, expected to come online in June 2023. The PPA was negotiated in conjunction with the Micron ESA, which states that Idaho Power will procure renewable resources to assist Micron in meeting a portion of its annual energy requirements with energy generated by those resources. While the renewable resource, Black Mesa Solar in this case, will not serve Micron directly, and rather will be connected to the Company’s system, Micron will pay for all of the output through its ESA.

Because Micron will be paying for 100 percent of Black Mesa Solar’s generation, the cost of the PPA was removed from the Company’s calculation of forecast NPSE. As recommended by Commission Staff in Order No. 35482, the Company has provided Black Mesa Solar’s forecast generation and expenses, as well as Micron’s monthly load forecast, as Confidential Exhibit No. 4.

Q. How will the excess generation and renewable capacity credit payments, as detailed in Micron’s ESA, be incorporated into this year’s PCA filing?

A. In the event that Black Mesa Solar’s generation exceeds Micron’s load in a given hour, the Company will compensate Micron for the excess generation according to the methodology approved by the Commission in Order No. 35482. However, for the 2023-2024 PCA year, the Company does not expect Black Mesa Solar’s generation to exceed Micron’s load in any hour. As a result, no excess generation payments are included in this year’s PCA forecast.

 In addition, as stated in Order No. 35482, the Company will not begin renewable capacity credit payments until July 1, 2026. As a result, no renewable capacity credit payments are included in this year’s PCA forecast.

Q. How does the Company’s forecast of system-level NPSE for the 2023-2024 PCA compare to the system-level forecast included in last year’s PCA?

A. Table 3 below compares this year’s 2023-2024 PCA forecast of NPSE to last year’s PCA forecast by FERC account. As detailed in this table, the PCA forecast on a total system basis for the 2023-2024 PCA year is $541,499,384, which is $52,004,084 higher than last year’s forecast amount of $489,495,300.

|  |  |
| --- | --- |
| **Table 3** | **PCA Forecast Comparison Expenses (Total System)** |
|   |   |  |  |   |
| **Line No.** | **FERC Account** | **2022-2023 Forecast** | **2023-2024 Forecast** | **Difference** |
|   | 95% Sharing Accounts |  |  |   |
| 1 | Account 501, Coal |  $ 151,179,160  |  $ 130,090,026  |  $ (21,089,135) |
| 2 | Account 536, Water for Power |  $ 0  |  $ 0  |  $ 0  |
| 3 | Account 547, Other Fuel |  $ 79,067,982  |  $ 134,623,640  |  $ 55,555,657  |
| 4 | Account 555, Purchased Power Non-PURPA |  $ 98,482,808  |  $ 123,492,688  |  $ 25,009,880  |
| 5 | Account 565, 3rd Party Transmission  |  $ 5,149,239  |  $ 7,964,649  |  $ 2,815,409  |
| 6 | Account 447, Surplus Sales |  $ (65,085,848) |  $ (84,191,539) |  $ (19,105,691) |
|   |   | $ 268,793,342  |  $ 311,979,464  |  $ 43,186,122  |
|   |   |  |  |   |
|   | 100% Sharing Accounts |  |  |   |
| 7 | Account 555, PURPA |  $ 212,586,058  |  $ 218,535,412  |  $ 5,949,354  |
| 8 | Account 555, Demand Response Incentives |  $ 8,115,900  |  $ 10,984,508  |  $ 2,868,608  |
|   |   |  $ 220,701,958  |  $ 229,519,920  |  $ 8,817,962  |
|   |   |  |  |   |
| 9 | Total PCA Forecast |  $ 489,495,300 |  $ 541,499,384  |  $ 52,004,084  |

Q. What general conclusions can be drawn from the information contained in Table 3?

A. When viewed by category, the 95 percent sharing accounts have increased approximately $43.2 million from last year’s forecast, while the 100 percent sharing accounts have increased approximately $8.8 million over last year’s forecast.

Q. What factors are contributing to the major differences presented in Table 3?

A. Forecast expenses included in the 95 percent sharing accounts are expected to increase by 16 percent as compared to last year, from $268,793,342 to $311,979,464. Due to the limited coal supply, the Company expects to rely more on natural gas generation and purchased power to serve load in the 2023-2024 PCA Year.

Q. Please explain the circumstances that led to the Company’s limited coal supply.

A. Global natural gas supply and demand disruptions over the last several months, stemming from the Russian invasion of Ukraine and sabotage of the Nord Stream pipelines, have caused price escalation and volatility in the natural gas and energy markets.

As the same time, the U.S. has been ramping down its coal production, limiting the supply of coal available to the electric utility sector. Similarly, production capabilities at Bridger Coal Company (“BCC”) have decreased as a result of the closing of the underground mining operations at the end of 2021.

 As a result of the price escalation and volatility in the natural gas and energy markets throughout 2022, Idaho Power increased its reliance on coal-fired generation to serve load. Actual coal-fired generation for the first 9 months of 2022 was 50 percent higher than the same period in 2021, and 30 percent higher than the 5-year average for the period.

The increase in coal-fired generation in 2022, combined with the closure of the underground mine at BCC, has resulted in a limited supply of coal available for use in 2023. Coal availability is expected to improve in 2024, however, when Bridger Units 1 and 2 are converted to natural gas fired units, thus reducing Idaho Power’s coal-fired fleet from 5 units to 3 units.

Q. How is Idaho Power working to limit the customer impact of the current coal constraints at the Bridger plant?

A. Idaho Power plans to use 100 percent of the available production capacity from BCC through 2023. Idaho Power is actively working with its operating partner at BCC, PacifiCorp, to identify opportunities to maximize coal production with existing infrastructure, resources, and equipment.

In addition to utilizing 100 percent of available production capacity at BCC, the Company has secured all available coal from its primary third-party supplier, Black Butte Coal Company, through 2023.

Idaho Power has also recently secured rail transportation that will allow for approximately 200,000 tons of spot coal to be delivered from the Powder River Basin (“PRB”) to the Bridger plant beginning in May 2023 through December 2023. While PRB coal has not been utilized at Bridger as a base fuel supply source to date due to its high propensity to spontaneously combust, the plant is capable of consuming PRB coal on a limited scale. Idaho Power intends to rely on as much PRB coal as can be delivered and burned safely at the plant in 2023.

Q. Has the Company and its partner considered increasing the capacity to produce coal at BCC?

A. Yes. However, no feasible, cost-effective methods of increasing coal production capacity in the short term have been identified. Increasing coal production at BCC to levels that would completely fill the shortfall in supply would require new permits and additional investment in capital infrastructure. Because the current coal supply constraints are not expected to persist after the conversion of Bridger Units 1 and 2 to natural gas, additional investment to fill the near-term temporary shortfall in coal supply would not provide a benefit to customers in the long-term.

Q. What is Idaho Power doing to address coal constraints at the Valmy plant?

A. At Valmy, Idaho Power is actively working to secure additional coal supply for 2023, 2024, and 2025. Solicitations made in a June 2022 Request for Proposal (“RFP”) seeking 2023 coal volumes from spot coal suppliers indicated minimal Western coal available and higher coal prices.

As a result of the knowledge gained from the June 2022 RFP, Idaho Power, and its co-owner of Valmy, NV Energy, commissioned an independent engineering firm to evaluate the performance capabilities of the current dry sorbent injection system and feasibility of installing activated carbon injection systems that would enhance controls to allow Valmy to burn higher mercury and sulfur coals. Based on information provided by the engineering firm, Valmy plant specifications for mercury and sulfur were refined.

In November 2022, NV Energy and Idaho Power issued a new RFP seeking coal for 2023. Idaho Power has scheduled a test burn for a new fuel source from this RFP, and a contract is being negotiated with the supplier pending finalization of rail transportation. Idaho Power expects that this volume of additional coal, combined with existing stockpile inventory, will provide fuel to operate Valmy during the summer months of 2023, as well as the winter months of 2023–24.

Q. Please elaborate on the changes in the 95 percent sharing accounts for this year’s forecast as compared with last year’s forecast as presented in Table 3.

A. For the 2023-2024 PCA year, the average forecast market purchase price is $76.01 per megawatt-hour (“MWh”), compared to $49.11 per MWh last year, an increase of 55 percent. In addition, the per-unit cost of natural gas for the 2023-2024 PCA year is $41.27 per MWh, an increase of 33 percent compared to last year. As a result of the limited coal supply, the per-unit cost of coal generation has also increased from last year. The average per-unit cost of coal-fired generation for the 2023-2024 PCA year is $36.95 per MWh, an increase of 24 percent compared to last year. Accordingly, expenses from non-PURPA purchased power are expected to increase 25 percent as compared to last year’s forecast, natural gas expense is expected to increase 70 percent, and coal fuel expense is expected to decrease 14 percent.

The increase in forecast market energy prices is also resulting in higher surplus sales revenue. Surplus sales revenue is expected to increase 29 percent compared to last year, from $65,085,848 to $84,191,539. For the 2023-2024 PCA Year, the average forecast market sales price is $82.96 per MWh compared with $51.73 last year, a 60 percent increase.

Q. What factors are contributing to the change in the 100 percent sharing accounts?

A. As can be seen in Table 3, forecast expenses included in the 100 percent sharing accounts are expected to increase by 4 percent as compared to last year, from $220,701,958 to $229,519,920. Forecast PURPA costs increased by $5.95 million as compared to last year’s forecast and forecast demand response incentive payments increased by $2.9 million as compared to last year.

Q. Is the increase in forecast PURPA costs related to increased generation output from PURPA projects?

A. In part. Table 4 details changes between last year’s PCA forecast and this year’s PCA forecast with respect to forecasted generation in MWh. As shown in Table 4, PURPA generation is anticipated to increase by 19,189 MWh, or less than 1 percent. The 3 percent increase in PURPA expense is largely the result of price escalation in PURPA contracts, for which the average cost is $71.47 per MWh, compared to $69.96 last year.

|  |  |
| --- | --- |
| **Table 4** | **PCA Forecast Comparison Generation (Total System-MWh)** |
|  |   |  |  |   |
| **Line No.** | **FERC Account** | **2022-2023 Forecast** | **2023-2024 Forecast** | **Difference** |
| 1 | Hydro |  5,972,743  |  6,487,995  |  515,252 |
|   | 95% Sharing Accounts |  |  |   |
| 2 | Account 501, Coal |  5,083,043  |  3,520,905  |  (1,562,138)  |
| 3 | Account 547, Other Fuel |  2,556,322  |  3,261,784  |  705,462  |
| 4 | Account 555, Purchased Power Non-PURPA |  1,580,326  |  1,695,683  |  115,357  |
|   | 95% Sharing Accounts |  15,192,435  |  14,966,367  |  (226,068)  |
|   |   |  |  |   |
|   | 100% Sharing Accounts |  |  |   |
| 5 | Account 555, PURPA |  3,038,613  |  3,057,802  |  19,189  |
|   | 100% Accounts |  3,038,613  |  3,057,802 |  19,189  |
|   |   |  |  |   |
| 6 | Total Generation |  18,231,048  |  18,024,169  |  (206,879)  |
|   |   |  |  |   |
|   | 95% Sharing Accounts |  |  |   |
| 7 | Account 447, Surplus Sales |  1,258,195  |  1,014,817  |  (243,978)  |
| 8 | Total Load |  16,972,853  |  17,009,352  | 36,499  |

Q. What other general conclusions can be drawn from the information in Table 4?

A. Compared to last year’s forecast, hydro generation is expected to increase from 5,972,743 MWh to 6,487,995 MWh, or 9 percent. Due to the limited coal supply, coal-fired generation is expected to decrease from 5,083,043 MWh to 3,520,905 MWh, or 31 percent. To offset the reduction in coal-fired generation, natural gas generation is expected to increase 28 percent compared to last year. In addition, non-PURPA purchased power is expected to increase 7 percent from last year. This 7 percent increase is due to an increase in PPA generation, more specifically, the increased forecast generation from Jackpot Solar, which came online in December 2022.

Q. What is causing the 9 percent increase in expected hydro generation?

A. The increase in expected hydro generation is mainly due to higher projected inflows into Brownlee reservoir. The March Operating Plan used in this year’s PCA forecast projects April through July inflows into Brownlee of 4.3 million acre-feet (“MAF”) as compared to 2.9 MAF used to determine last year’s PCA forecast, an increase of 69 percent. Expected inflows into Brownlee are higher than last year’s PCA forecast as a result of better snowpack conditions, which provide for sustained runoff and increased hydro generation during the spring and summer months. Snowpack conditions used to determine this year’s PCA hydro forecast are 117 percent of normal, compared to 76 percent of normal last year.

Q. How are the forecasted NPSE differences presented in Table 2 used to determine the 2023-2024 PCA forecast component to be collected from Idaho customers?

A. The 2023-2024 PCA forecast component reflects the Idaho jurisdictional share of the forecasted NPSE differences presented in Table 2, adjusted for the PCA sharing provisions. The Idaho jurisdictional share of the forecast NPSE differences is determined by applying a ratio of forecast firm Idaho jurisdictional sales to forecast firm system-level sales to the system-level NPSE differences.

Q. Were any changes made to the Idaho jurisdictional sales and system-level sales to account for the portion of Micron’s load met by Black Mesa Solar?

A. Yes. The portion of Micron’s load forecast to be met by Black Mesa Solar was removed from the total forecast Idaho jurisdictional sales and system-level sales and was not used in the derivation of the PCA rate.

Q. What is the Company’s forecast of system-level firm sales and Idaho jurisdictional firm sales, net of the

portion of Micron’s load met by Black Mesa Solar, for the 2023-2024 PCA Year?

A. For the 2023-2024 PCA Year, Idaho Power has forecast system-level firm sales to be 15,662,267 MWh and Idaho jurisdictional firm sales to be 14,960,556 MWh, or 95.52 percent of the system level.

Q. What is the Company’s determination of the 2023-2024 PCA forecast component to be collected from Idaho customers?

A. The 2023-2024 PCA forecast component to be collected from Idaho customers is $218,006,526. Table 5 presents the determination of the 2023-2024 PCA forecast component by individual PCA expense and revenue category.

|  |  |
| --- | --- |
| **Table 5** | **2023-2024 PCA FORECAST** |
|   |   |  |  |   |
| **Line No.** | **FERC Account** | **Difference from Base** | **Difference After Sharing** | **Idaho Allocation** |
|   | 95% Sharing Accounts | (From Table 1) |  |   |
| 1 | Account 501, Coal |  $ 21,586,845  |  $ 20,507,503  |  $ 19,588,713  |
| 2 | Account 536, Water for Power |  $ (2,380,597) |  $ (2,261,567) |  $ (2,160,243) |
| 3 | Account 547, Other Fuel |  $ 101,256,077  |  $ 96,193,273  |  $ 91,883,560  |
| 4 | Account 555, Purchased Power Non-PURPA |  $ 60,886,095  |  $ 57,841,790  |  $ 55,250,325  |
| 5 | Account 565, 3rd Party Transmission  |  $ 2,508,694  |  $ 2,383,259  |  $ 2,276,483  |
| 6 | Account 447, Surplus Sales |  $ (32,456,386) |  $ (30,833,566) |  $ (29,452,141) |
|   |   |  $ 151,400,729  |  $ 143,830,692  |  $ 137,386,697  |
|   |   |  |  |   |
|   | 100% Sharing Accounts |  |  |   |
| 7 | Account 555, PURPA |  $ 84,681,543  |  $ 84,681,543  |  $ 80,887,586  |
| 8 | Account 555, Demand Response Incentives |  $ (267,757) |  $ (267,757) |  $ (267,757) |
| 9 | Total |  $ 235,814,515  |  $ 228,244,478  |  $ 218,006,526  |

**B. Balancing Adjustment.**

Q. What is this year’s quantification of the Balancing Adjustment?

A. The Balancing Adjustment is detailed in the PCA deferral report, attached hereto as Exhibit No. 2. This report compares actual NPSE amounts to actual power cost collections monthly, with the differences accumulated as a deferral balance. The balance at the end of March 2023, with interest applied, was $190,205,569 as shown on row 100 of Exhibit No. 2. The approximate $190 million represents an increase to customer rates in this year’s PCA Balancing Adjustment.

Q. To what factors do you attribute the accumulation of the approximate $190 million deferral balance?

A. The approximate $190 million deferral balance was primarily driven by a decrease in actual hydro generation from expected as well as higher than forecast market purchases and natural gas generation, due to a limited coal supply.

Actual hydro generation for the 2022-2023 PCA year totaled 5,458,343 MWh, a 9 percent decrease from last year’s forecast of 5,972,743 MWh. Actual purchased power totaled 4,297,723 MWh, a 172 percent increase from last year’s forecast. Actual natural gas generation totaled 2,716,835 MWh, a 6 percent increase from last year’s forecast. Lastly, actual surplus sales volumes totaled 1,455,119 MWh, an increase of 16 percent from last year.

Actual natural gas and market energy prices were also higher than forecast, driving a 126 percent increase in natural gas fuel expense and a 318 percent increase in purchased power expense.

In addition, due to the limited coal supply, the Company began optimizing its coal-fired generation dispatch in October 2022. At a high level, this dispatch optimization process involved reducing coal unit dispatch during lower market price conditions to ensure the plants were available to operate during high load and/or high market price conditions. As a result, actual coal-fired generation totaled 3,265,218 MWh, a decrease of 36 percent compared to last year’s forecast.

Q. Please elaborate on the changes in actual versus forecast generation and expense for the 2022-2023 PCA Year.

A. Last year’s PCA forecast included an average market sales price of $51.73 per MWh. The actual average market sales price for the 2022-2023 PCA year was $116.98 per MWh, a 126 percent increase. As a result of the difference in forecast and actual market sales prices, as well as economic opportunity during the spring and winter months of the 2022-2023 PCA year, actual surplus sales volumes were 16 percent higher than forecast. Surplus sales revenue totaled $170,224,982, which was 162 percent higher than forecast revenues of $65,085,848.

As mentioned above, actual coal-fired generation for the 2022-2023 PCA year was 36 percent lower than forecast. Actual coal fuel expense totaled $94,955,998, which was 37 percent lower than forecast. Coal-fired generation was lower than forecast due to the limited coal supply, as discussed earlier in testimony.

Natural gas generation totaled 2,716,835 MWh for the 2022-2023 PCA Year, which was 6 percent higher than forecast. Due to the increased natural gas prices, actual natural gas expense totaled $178,317,313, which was 126 percent higher than forecast. While natural gas prices were higher than forecast, the Company’s reliance on natural gas generation increased 6 percent as it was needed to meet load, as well as make off-system sales when it was economic, as noted previously.

While both purchased power and surplus sales increased, surplus sale volumes were highest in off-peak spring and winter months, and purchased power was highest in summer months, where hot temperatures caused continuously higher than forecast peak loads.

Q. Were there any items included in this year’s Balancing Adjustment in addition to actual NPSE incurred during the April 2022 through March 2023 period?

A. Yes. Per Commission Order No. 34100, Idaho Power included its actual costs of Western Energy Imbalance Market (“EIM”) participation for April 2022 through March 2023 in the Balancing Adjustment. Benefits associated with EIM participation are embedded in actual NPSE experienced over that same period.

Q. Please summarize the conditions of Order No. 34100 as they pertain to EIM cost recovery through the 2022 PCA.

A. Per the terms of the settlement stipulation (“EIM Stipulation”) approved by Order No. 34100, Idaho Power agreed to include an EIM-related monthly revenue requirement in its monthly PCA deferral calculation based on actual EIM participation costs commencing April 1, 2018. The Company also agreed to apply a soft cap to EIM-related revenue requirement included in the PCA deferral equal to annual EIM benefits as reported by the California Independent System Operator (“CAISO”) for the corresponding period.

Q. Is the EIM-related revenue requirement included in the April 2022 through March 2023 PCA deferral under the soft cap of annual CAISO-reported benefits for that same period?

A. Yes. For the April 2022 through March 2023 period, the EIM-related revenue requirement totaled $2.5 million, while CAISO reported EIM benefits for Idaho Power of approximately $37.7 million from April through December (CAISO’s first quarter 2023 report has not yet been published). Therefore, the Company’s EIM-related revenue requirement is less than the soft cap agreed to in the EIM Stipulation.

Q. Does Idaho Power believe the EIM has provided net benefits to customers since joining in April 2018?

A. Yes. While Idaho Power believes the CAISO benefit calculation overstates estimated benefits to Idaho Power’s system, the Company believes customers have realized significant net benefits since the Company’s entry into the EIM in April 2018. As discussed in the Company’s May 24, 2019, Report of EIM Benefits and Costs of Participation, filed in Case No. IPC-E-16-19, Idaho Power has developed a more precise methodology for determining EIM benefits that uses inputs specific to the Company. Based on this methodology, the Company believes benefits achieved between April 2022 and December 2022 are approximately $9 million (benefits for the first quarter of 2023 are not yet available). This level of EIM benefits compared to the Idaho-jurisdictional EIM costs of $2.5 million, demonstrates a net benefit to the Company and, ultimately, its customers.

1. **PCA Rate Determination.**

Q. How is the rate for the forecast portion of the PCA for April 2023 through March 2024 determined?

A. The rate for the forecast portion of the PCA is equal to the sum of (1) 95 percent of the difference between the non-PURPA expenses quantified in the Operating Plan and those quantified in the Company’s last approved update of NPSE, divided by the Company’s forecast of system firm sales for June 1, 2023, through May 31, 2024[[3]](#footnote-3) (“System-level Sales Forecast”); and (2) 100 percent of the difference between PURPA-related expenses quantified in the Operating Plan and those quantified in the Company’s last approved update of NPSE, divided by the Company’s System-level Sales Forecast; and (3) 100 percent of the difference between the Idaho jurisdictional demand response incentive payments quantified in the Operating Plan and those quantified in the Company’s last approved update of NPSE, divided by the forecast of Idaho jurisdictional firm sales[[4]](#footnote-4) for June 1, 2023, through May 31, 2024.

Q. What is the rate for the forecast portion of the PCA for April 2023 through March 2024?

A. The rate for non-PURPA expenses is 0.9183 cents per kilowatt-hour (“kWh”), which is calculated by multiplying $151,400,729 from Table 2 by 95 percent and then dividing it by the System-level Sales Forecast, net of Black Mesa Solar generation, of 15,662,267 MWh (($151,400,729 \* 0.95) / 15,662,267) = $9.183 /MWh = 0.9183 cents/kWh). The rate for PURPA expenses is 0.5407 cents per kWh, which is calculated by dividing $84,681,543 from Table 2 by the 15,662,267 MWh ($84,681,543 / 15,662,267 MWh = $5.407/MWh = 0.5407 cents/kWh). The rate for demand response incentive payments is negative 0.0018 cents per kWh, which is calculated by dividing the negative $267,757 from Table 2 by the forecast of Idaho jurisdictional firm sales, net of Black Mesa Solar generation, of 14,960,556 MWh (‑$267,757 / 14,960,556 MWh = -$0.0180/MWh = -0.0018 cents/kWh). The forecast portion of the PCA rate is 1.4572 cents per kWh, which is calculated by adding the non-PURPA expense of 0.9183 cents per kWh to the PURPA expense of 0.5407 cents per kWh to the demand response incentive payment of negative 0.0018 cents per kWh (0.9183 + 0. 5407 + -0.0018 = 1.4572 cents/kWh).

Q. How did you compute this year’s Balancing Account rate?

A. As shown in Exhibit No. 2, this year’s Balancing Adjustment of the PCA is approximately $190 million, which, when divided by the Company’s forecast of Idaho jurisdictional sales, net of Black Mesa generation, of 14,960,556 MWh, results in a rate of 1.2714 cents per kWh ($190,205,569 / 14,960,556 = $12.714/MWh = 1.2714 cents/kWh).

Q. What is the resulting PCA rate when you combine all the PCA components described previously?

A. The uniform PCA rate comprises (1) the 1.4572 cents per kWh for the 2023-2024 projected power cost of serving firm loads under the current PCA methodology and 95 percent sharing, and (2) the 1.2714 cents per kWh for the 2022-2023 Balancing Adjustment of the PCA. The sum of these two components is a 2.7286 cents per kWh charge for all rate classes.

1. **ADDITIONAL PCA RATE ADJUSTMENTS**

**A. Revenue Sharing.**

Q. When was the revenue sharing mechanism originally established?

A. The revenue sharing mechanism was originally established in Case No. IPC-E-09-30 and approved in Order No. 30978, effective for the years 2009-2011. Since then, the revenue sharing mechanism has been modified and extended three times.[[5]](#footnote-5) Most recently, the revenue sharing mechanism was extended indefinitely, with modifications, in Order No. 34071 in Case No. GNR-U-18-01.

Q. What are the provisions of the current revenue sharing mechanism?

A. In Case No. GNR-U-18-01, the Company filed a motion to approve a settlement stipulation (“2018 Stipulation”) extending the sharing mechanism indefinitely, with modifications. The Commission approved the 2018 Stipulation in Order No. 34071.

Per the terms of the 2018 Stipulation, if the Company’s actual year-end Return on Equity (“ROE”) for the Idaho jurisdiction exceeds 10 percent, all amounts up to and including a 10.5 percent ROE will be shared between customers and the Company on an 80 percent and 20 percent basis, respectively, to be provided as a rate reduction to become effective at the time of the subsequent year’s PCA. If the Company’s Idaho jurisdictional ROE exceeds 10.5 percent, all amounts in excess of 10.5 percent will be shared 55 percent with Idaho customers as a rate reduction to become effective with the subsequent year’s PCA, 25 percent will be shared with Idaho customers in the form of an offset to amounts in the Company’s pension balancing account, and 20 percent will be apportioned to the Company.

With regard to the amortization of Accumulated Deferred Investment Tax Credits (“ADITC”), the 2018 Stipulation allows the Company to accelerate the amortization of ADITC, in an amount up to $45 million, to achieve a maximum 9.4 percent Idaho jurisdictional ROE if the Company’s year-end actual results fall below that amount for any year beginning January 1, 2020. Idaho Power may use up to $25 million of additional amortization of ADITC per year, provided the total, cumulative amount of ADITC does not exceed $45 million. Per the 2018 Stipulation, once the Company has fully amortized the $45 million of ADITC, revenue sharing will cease; however, Idaho Power may at any time request to replenish the total amount of ADITC it is permitted to amortize, and if approved by the Commission, revenue sharing would continue.

Q. What have been the results of the revenue sharing mechanism since it was implemented through 2021?

A. The Company’s earnings in each year from 2011 through 2015, as well as 2018 and 2021, resulted in revenue sharing with customers totaling $126.7 million, either as a direct rate offset in the PCA or as an offset to amounts that would have otherwise been collected in rates. The Company’s earnings in 2016, 2017, 2019, and 2020 were below the revenue sharing threshold. These amounts are detailed in Table 6 below.

|  |  |
| --- | --- |
| **Table 6** | **2009-2022 Revenue Sharing** |
| **Line No.** | **Revenue Sharing Component** | **2009-2011** | **2012-2014** | **2015-2019** | **2020-2022** |   |
| 1 | Available ADITC For Use | $45 Million | $45 Million | $45 Million | $45 Million |   |
| 2 | Customer Benefits ($ Millions): |  |  |  |  |   |
| 3 | Reduction to Rates | $27.1 | $22.8  | $8.2  | $0.6  | **Total** |
| 4 | Offset to Pension Balancing Account | $20.3  | $47.8  | $0.0  | $0.0  | **2009-2022** |
| 5 | **Total** | $47.4  | $70.6  | $8.2  | $0.6  | **$126.7**  |
|  |  |  |  |  |  |  |

Q. Did the Company’s year-end 2022 financial results warrant any action related to the existing sharing agreement per the terms of the 2018 Stipulation?

A. No. The Company’s year-end 2022 financial results yielded an actual Idaho jurisdictional ROE of 9.8 percent, falling below the 10 percent ROE threshold for revenue sharing, and thus resulting in no revenue sharing with customers.

Q. Did the Company use the same methodology to determine the Idaho jurisdictional 2022 year-end ROE that was used in prior PCA filings?

A. Yes. The methodology used to determine the Company’s Idaho jurisdictional 2022 year-end ROE is consistent with the methodology used for the year-end ROE determinations since the inception of the mechanism.

Q. Do you have an exhibit demonstrating the application of this methodology?

A. Yes. Exhibit No. 3 provides a step-by-step calculation of the Idaho jurisdictional ROE based on year-end 2022 financial results utilizing the Commission-approved methodology from previous PCA filings.

**IV. NET CUSTOMER IMPACT**

Q. What is the revenue impact of the requested PCA rate when compared with PCA rates currently in effect?

A. Attachment 2 to the Application filed contemporaneously with my testimony provides a detailed description of the overall revenue impact of this filing on each customer class. As shown in Attachment 2, applying the requested PCA rates to expected customer sales for the June 2023 through May 2024 test year[[6]](#footnote-6) results in a PCA increase of $200.2 million.

Q. Given the magnitude of the increase for the 2023-2024 PCA, did the Company consider proposing any rate mitigation options?

A. Yes, though after careful consideration it was ultimately decided to not propose any rate mitigation measures in this case. While the Company is sensitive to the financial impact the proposed increase will have on its customers, it believes the potential longer-term downside risks outweigh the near-term relief of deferring all or a portion of the requested increase.

Q. What concerns does the Company have with proposing rate mitigation measures in this case?

A. First, the Company believes that customer interests are generally best served by matching cost recovery as closely as possible with the period in which power supply costs are incurred. Additionally, mitigating rate impacts by spreading recovery over multiple years creates the possibility that the deferred collection will result in “rate pancaking” with potential future rate increases, essentially deferring an increase in the current year to create an even larger increase in the future.

Q. Is the Company’s decision not to propose any rate mitigation measures in this case consistent with Commission precedent?

A. Yes. In considering the use of rate mitigation measures in prior PCA cases, the Commission has repeatedly declined to spread recovery of amounts into subsequent years citing concerns surrounding rate pancaking, appropriate matching of costs and recovery, and the overall intent of the PCA mechanism.[[7]](#footnote-7)

Q. Would Idaho Power be amenable to implementing rate mitigation measures for the 2023-2024 PCA if the Commission determines such measures are appropriate?

A. Yes. While both Idaho Power and the Commission have expressed concerns with rate mitigation measures in the past, the Company would be amenable to discussing such measures in the current filing. A two-year recovery period, for example, would reduce the rate impact from the proposed $200.2 million, or 14.68 percent increase, to an approximate $100 million, or slightly more than 7 percent, annual increase in collection spread over two years.

Q. Have you prepared a revised Schedule 55 that includes the proposed PCA rates?

A. Yes. Attachment 1 to the Application is a revised Schedule 55 and includes the proposed PCA rates in clean and legislative formats.

Q. Please summarize the Company’s request in this filing.

A. If approved, the 2023-2024 PCA will result in an increase in total billed revenue of approximately $200.2 million, or 14.68 percent. The Commission should approve the Company’s computation of the PCA rates, the calculation of which follows the methodology that was approved in Order Nos. 30715, 33307, and 34071.

Q. Does this conclude your testimony?

A. Yes, it does.

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

**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. 1-4 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 14th day of April 2023, at Boise, Idaho.



 Signed: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

1. *In the Matter of the Application of Idaho Power Company for Authority to Establish a New Base Level of Net Power Supply Expense,* Case No. IPC-E-13-20, Order No. 33000 (March 21, 2014). [↑](#footnote-ref-1)
2. *In the Matter of the Replacement Special contract with Micron Technology, Inc. and Purchase Agreement with Black Mesa Energy LLC,* Case No. IPC-E-22-06, Order No. 35482 (August 01, 2022). [↑](#footnote-ref-2)
3. System-level and Idaho jurisdictional firm sales used in the calculation are net of Black Mesa Solar’s forecasted generation for the June 2023 – May 2024 time period. [↑](#footnote-ref-3)
4. *Id*. [↑](#footnote-ref-4)
5. Order Nos. 32424, 33149 and 34071. [↑](#footnote-ref-5)
6. Expected customer sales for the June 2023 – May 2024 test year are reduced by the amount of Micron’s load forecast to be met by Black Mesa Solar generation for the reasons explained herein. [↑](#footnote-ref-6)
7. See, e.g., Order Nos. 28722, 29026, 30563, 30828, and 32821. [↑](#footnote-ref-7)