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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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| 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, 2020, THROUGH MAY 31, 2021. | ) ) ) ) ) ) ) | CASE NO. IPC-E-20-21 |

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

Timothy E. Tatum

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

A. My name is Timothy E. Tatum. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Vice President of Regulatory Affairs.

Q. Please describe your educational background.

A. I earned a Bachelor of Business Administration degree in Economics and a Master of Business Administration degree from Boise State University. I have also attended electric utility ratemaking courses, including "Practical Skills for The Changing Electrical Industry," a course offered through New Mexico State University's Center for Public Utilities, "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Electric Utilities Consultants, Inc., and Edison Electric Institute's "Electric Rates Advanced Course." In 2012, I attended the Utility Executive Course ("UEC") at the University of Idaho, and subsequently became a member of the UEC faculty in 2015.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1996 in the Company's Customer Service Center where I handled customer phone calls and other customer-related transactions. In 1999, I began working in the Customer Account Management Center where I was responsible for customer account maintenance in the areas of billing and metering.

In June of 2003, I began working as an Economic Analyst on the Energy Efficiency Team. As an Economic Analyst, I was responsible for ensuring that the demand-side management ("DSM") expenses were accounted for properly, preparing and reporting DSM program costs and activities to management and various external stakeholders, conducting cost-benefit analyses of DSM programs, and providing DSM analysis support for the Company's Integrated Resource Plan.

In August of 2004, I accepted a position as a Regulatory Analyst in the Regulatory Affairs Department. As a Regulatory Analyst, I provided support for the Company's various regulatory activities, including tariff administration, regulatory ratemaking and compliance filings, and the development of various pricing strategies and policies.

In August of 2006, I was promoted to Senior Regulatory Analyst. As a Senior Regulatory Analyst, my responsibilities expanded to include the development of complex financial studies to determine revenue recovery and pricing strategies, including the preparation of the Company's cost-of-service studies.

In September of 2008, I was promoted to Manager of Cost of Service and, in April of 2011, I was promoted to Senior Manager of Cost of Service and oversaw the Company's cost-of-service activities, such as power supply modeling, jurisdictional separation studies, class cost-of-service studies, and marginal cost studies.

In March 2016, I was promoted to Vice President of Regulatory Affairs. As Vice President of Regulatory Affairs, I am responsible for the overall coordination and direction of the Regulatory Affairs Department, including development of jurisdictional revenue requirements and class cost-of-service studies, preparation of rate design analyses, and administration of tariffs and customer contracts.

Q. What is the Company requesting in this case?

A. The Company is requesting approval of its 2020-2021 PCA rates to become effective June 1, 2020. If approved, the 2020-2021 PCA will result in an increase in total billed revenue of approximately $58.7 million, or 5.21 percent.

Q. How is the Company's case organized?

A. The Company's case includes testimony from two witnesses. My testimony consists of four sections. In the first section, I provide an overview of the PCA. In the second section, I detail the 2020-2021 PCA amount in comparison to last year’s PCA amount, and identify and discuss the main factors contributing to this change. In the third section of my testimony, I detail the net customer impact of the 2020-2021 PCA rates if approved as filed. In the final section, I describe Idaho Power’s careful consideration of this request in light of the financial challenges the Company and its customers are currently facing as a result of the 2019 Novel Coronavirus (“COVID-19”) health crisis.

Nicole A. Blackwell, a Regulatory Analyst in the Regulatory Affairs Department, also provides testimony in this case. Ms. Blackwell’s testimony provides quantification of the 2020-2021 PCA forecast amount, discusses additional PCA components related to revenue sharing and tax reform benefits, and presents the quantification of the 2020-2021 PCA rates to become effective June 1, 2020.

## I. PCA OVERVIEW

Q. What is the purpose of the PCA and how does the mechanism function?

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 True-up component ("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 True-up component includes a backward-looking tracking of differences between the prior PCA year's forecast and actual NPSE incurred by the Company. The True-up contains a second component that tracks the collection of the prior year's True-up amount, referred to as the "True-up of the True-up."

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 Idaho Public Utilities Commission ("Commission") in Order No. 33149.

Q. Does the revenue collected from customers through the annual PCA rate contribute toward the Company's net income?

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 NPSE 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. 2020-2021 PCA

Q. What is the total PCA collection that would result under the 2020-2021 PCA rates proposed by the Company in this case?

A. The 2020-2021 PCA rates, as quantified in Ms. Blackwell's testimony, would result in total PCA collection of $69.8 million.  This represents an increase in total billed revenue of $58.7 million for the upcoming year, an increase of 5.21 percent.

Q. Have you prepared a table that details the $58.7 million revenue impact by component?

A. Yes.  Table 1 below presents a separation of the $58.7 million increase into each component included in the Company's proposed rates.

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| Table 1 | | Revenue Impact by Component | | |
|---|---|---|---|---|
| **Line No.** | **Rate Component** | **2019-2020 PCA[1]** | **2020-2021 PCA[2]** | **Difference** |
| 1 | PCA forecast | $ 83,775,043 | $ 112,441,726 | $ 28,666,683 |
| 2 | PCA True-up | $(64,855,320) | $ (42,648,330) | $ 22,206,990 |
| 3 | PCA Total | $ 18,919,723 | $ 69,793,396 | $ 50,873,673 |
| 4 | Revenue Sharing | $ (5,096,850) | $ 0 | $ 5,096,850 |
| 5 | Tax Reform | $ (2,715,902) | $ 0 | $ 2,715,902 |
| 6 | **PCA Total** | **$ 11,214,205** | **$ 69,793,396** | **$ 58,686,425** |

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

A. The increase in this year's PCA largely reflects the return to a more normal level of NPSE as market energy prices have come down from unusually high levels reflected in last year's PCA. While it may seem counter-intuitive, NPSE expenses for Idaho Power tend to be lower during periods of higher market energy prices as resulting increased surplus sales revenues help to offset power supply costs.

The increase in this year's PCA forecast component is mostly attributable to lower hydro generation and significantly lower surplus sales revenues as compared to

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[1] Because Table 1 contains the expected billed revenue impact to customers, the "2019-2020 PCA" column reflects approved 2019-2020 PCA rates applied to the June 2020 through May 2021 sales forecast, and will not tie to the specific dollar amounts approved in the 2019 PCA filing.

[2] The "2020-2021 PCA" column reflects the Company's proposed rates applied to the June 2020 through May 2021 forecast, and may not tie exactly to the figures listed in the Company's testimony due to the rounding of rates to six digits.

last year's forecast. The PCA true-up component is also increasing as a result of lower surplus sales revenue.

In addition to the changes in the PCA forecast and True-up components, the currently effective PCA includes $7.7 million in one-time customer benefits associated with revenue sharing and tax reform, which will expire at the end of the current PCA-year. These adjustments are more fully described in Ms. Blackwell's testimony.

Q. Why do you believe that this year's proposed PCA collection reflects a return to a more "normal" level?

A. Table 2 below includes this year's proposed PCA revenue collection compared to the prior four years, inclusive of the forecast and True-up components.

| **Table 2** | **PCA Revenue Collection** | | | | |
|---|---|---|---|---|---|
| | **2016-2017 PCA** | **2017-2018 PCA** | **2018-2019 PCA** | **2019-2020 PCA** | **2020-2021 PCA** |
| | $ 86,358,618 | $ 103,129,716 | $ 69,415,883 | $ 18,679,456 | $ 69,793,396 |

Table 2 demonstrates that last year's PCA stands out as an anomaly as compared to the other four years supporting the conclusion that the proposed increase in billed revenue associated with this year's PCA request reflects a more normal level of NPSE.

**A. <u>PCA Forecast</u>.**

Q. How does the Company's forecast of system-level NPSE for the 2020-2021 PCA compare to the system-level forecast included in last year's PCA?

A. Table 3 below compares this year's 2020-2021 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 2020-2021 PCA Year is $426,904,721, which is $32,615,794 higher than last year's forecast amount of $394,288,927.

| Table 3 | PCA Forecast Comparison Expenses (Total System) | | | |
|---|---|---|---|---|
| | | | | |
| Line No. | FERC Account | 2019-2020 Forecast | 2020-2021 Forecast | Difference |
| | 95% Sharing Accounts | | | |
| 1 | Account 501, Coal | $ 146,631,692 | $ 102,534,012 | $ (44,097,680) |
| 2 | Account 536, Water for Power | $ 0 | $ 1,500,000 | $ 1,500,000 |
| 3 | Account 547, Other Fuel | $ 44,723,759 | $ 42,599,268 | $ (2,124,490) |
| 4 | Account 555, Purchased Power Non-PURPA | $ 62,039,274 | $ 89,849,920 | $ 27,810,645 |
| 5 | Account 565, 3rd Party Transmission | $ 5,319,681 | $ 5,058,450 | $ (261,230) |
| 6 | Account 447, Surplus Sales | $ (64,129,054) | $ (16,076,860) | $ 48,052,195 |
| | | $ 194,585,351 | $ 225,464,790 | $ 30,879,439 |
| | | | | |
| | 100% Sharing Accounts | | | |
| 7 | Account 555, PURPA | $ 192,301,878 | $ 193,826,319 | $ 1,524,441 |
| 8 | Account 555, Demand Response Incentives | $ 7,401,698 | $ 7,613,612 | $ 211,914 |
| | | $ 199,703,576 | $ 201,439,931 | $ 1,736,355 |
| | | | | |
| 9 | Total PCA Forecast | $ 394,288,927 | $ 426,904,721 | $ 32,615,794 |

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 $30.9 million from last year's forecast, while the 100 percent sharing accounts have increased approximately $1.7 million over last year's forecast.

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

A. Due to a return to more normal market energy price levels in this year’s PCA forecast, as well as a reduction in forecast hydro generation, surplus sales revenue is expected to decrease. The decrease in market energy prices is also contributing to a reduction in forecast coal-fired generation as it is less economic for load service as well as off-system sales. Conversely, due to the lower market energy prices, the Company is expected to increase market power purchases.

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

A. The decrease in forecast market energy prices is causing a $27,810,645 increase in non-PURPA purchased power, a 45 percent increase over last year’s forecast. Non-PURPA purchased power expense includes market power purchases as well as power purchase agreements (“PPAs”). The increase in forecast non-PURPA purchased power is primarily related to market power purchases, which are expected to increase from $14,898,672 in last year’s PCA forecast to $41,404,266 in this year’s PCA forecast, a 178 percent increase. For the 2020-2021 PCA Year, the average forecast market purchase price is $27.14 per megawatt-hour (“MWh”), as compared with $36.73 in last year’s PCA forecast, a 26 percent decrease.

At the same time, surplus sales revenues are expected to decrease 75 percent as compared to last year, from $64,129,054 to $16,076,860. For the 2020-2021 PCA year, the average forecast market sales price is $15.14 per MWh compared with $35.84 last year. The reduction in surplus sales is also driven by a reduction in hydro generation, which will be discussed later.

Due to the decrease in market energy prices, the Company's use of coal-fired generation, both for serving load as well as making economic surplus sales, is expected to decrease. Coal fuel expense is expected to decrease 30 percent as compared to last year's forecast, from $146,631,692 to $102,534,012.

Forecast fuel expense at the Company's natural gas plants is expected to decrease $2,124,490, or approximately 5 percent, as compared to last year's forecast due to lower natural gas prices. The average per-unit cost of natural gas generation in this year's PCA forecast is $21.59 per MWh compared to $23.04 per MWh last year, a 6 percent decrease.

Finally, this year's PCA forecast includes water lease expense whereas last year's PCA forecast did not. While the Company has not yet procured the water lease, it anticipates water will be available due to snowpack conditions in the Upper Snake basin, which is discussed in more detail later. Idaho Power has estimated water lease expense of $1,500,000 for this year's PCA forecast.

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

A. Forecast expenses included in the 100 percent sharing accounts are expected to increase by less than 1 percent as compared to last year, from $199,703,576 to $201,439,931. This change includes an increase in forecast PURPA expense of $1,524,441 as compared to last year, which is less than 1 percent, and a $211,914 increase, or 3 percent, in forecast demand response incentive payments.

Q. How does forecast generation for this year's PCA forecast compare to last year?

A. Table 4 below 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, the changes in total-system generation are related to coal, non-PURPA purchased power and surplus sales, similar to the changes in expense.

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| Table 4 | PCA Forecast Comparison Generation (Total System-MWh) | | | |
|---|---|---|---|---|
| Line No. | FERC Account | 2019-2020 Forecast | 2020-2021 Forecast | Difference |
| 1 | Hydro | 7,542,353 | 7,341,717 | (200,636) |
| | | - | | |
| | 95% Sharing Accounts | - | | |
| 2 | Account 501, Coal | 4,477,177 | 2,972,154 | (1,505,023) |
| 3 | Account 547, Other Fuel | 1,941,257 | 1,973,546 | 32,289 |
| 4 | Account 555, Purchased Power Non-PURPA | 974,474 | 2,095,454 | 1,120,980 |
| | 95% Sharing Accounts | 14,935,262 | 14,382,871 | (552,391) |
| | | | | |
| | 100% Sharing Accounts | | | |
| 5 | Account 555, PURPA | 2,962,728 | 2,976,554 | 13,826 |
| | 100% Accounts | 2,962,728 | 2,976,554 | 13,826 |
| | | | | |
| 6 | Total Generation | 17,897,990 | 17,359,425 | (538,565) |
| | | | | |
| | 95% Sharing Accounts | | | |
| 7 | Account 447, Surplus Sales | 1,789,397 | 1,062,077 | (727,320) |
| 8 | Total Load | 16,108,593 | 16,297,348 | 188,755 |

Q. Please elaborate on the changes in generation for this year’s forecast as compared with last year’s forecast.

A. Compared to last year’s forecast, coal-fired generation is expected to decrease 1,505,023 MWh, or 34 percent. As discussed previously, the decrease in market energy prices is contributing to the decrease in coal-fired generation as it is less economic to dispatch for surplus sales and to serve load. The retirement of one unit at the North Valmy coal-fired plant (“Valmy”) in December 2019, as well as the retirement of the Boardman coal-fired plant (“Boardman”) in December 2020, are also contributing to the decrease in coal-fired generation. This year’s PCA includes generation of 167,912 MWh at Valmy and 104,191 MWh at

Boardman as compared to 618,539 MWh and 330,559 MWh, respectively, for last year. The reduction in generation at these plants as compared to last year is due in part to the units no longer being available, but also due to economics.

The decrease in market energy prices is causing an increase in non-PURPA purchased power of 1,120,980 MWh. As mentioned previously, non-PURPA purchased power is comprised of market power purchases and PPAs. The market power purchases component is expected to increase 1,116,377 MWh, or 273 percent, while PPAs are expected to increase by 4,603 MWh, or less than 1 percent. The decrease in market energy prices is also causing a 41 percent decrease in surplus sales volumes as compared to last year, from 1,789,397 MWh to 1,062,077 MWh.

Finally, hydro generation is expected to decrease by 200,636 MWh, or 3 percent, from last year's forecast. The decrease in expected hydro generation is also contributing to the reduction in surplus sales.

Q. What is causing the decrease in expected hydro generation of 200,636 MWh?

A. The decrease in expected hydro generation is mainly due to lower projected inflows into Brownlee reservoir. The March Operating Plan used in this year's PCA forecast projects April through July inflows into Brownlee of 4.6 million acre-feet ("MAF") as compared with

5.0 MAF used to determine last year’s PCA forecast, a decrease of 8 percent.  Expected inflows into Brownlee were higher for 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. Although snowpack conditions in the Upper Snake River Basin, which directly impact stream flows at Milner Dam and, subsequently, through the majority of Idaho Power’s hydroelectric plants, are above normal for this year’s PCA forecast, snowpack conditions in the Boise and Payette Basins are well below normal. Weaker snowpack conditions in these basins are causing lower projected inflows into Brownlee and a reduction in forecast hydro generation for this year’s PCA forecast as compared to last year.

Q. Why is the decrease in forecast hydro generation not proportional to the decrease in expected inflows at Brownlee as compared to last year?

A. Although forecasted inflows into Brownlee are 8 percent lower for the months of April through July as compared to last year, total forecast generation is only 2 percent lower than last year. This is due to strong carryover from last year. This year’s PCA forecast reflects improved reservoir storage conditions, as compared to last year’s forecast. The March Operating Plan used in this year's PCA demonstrates that available storage in the 11 reservoirs above Brownlee is 125 percent of normal and at 82 percent of capacity, compared to last year's 2019 March Operating Plan, in which storage was 110 percent of normal and at 74 percent of capacity.

**B. <u>True-up and True-up of the True-up</u>.**

Q. What is this year's quantification of the True-up?

A. The True-up portion of the PCA is detailed in the deferral expense report, attached hereto as Exhibit No. 1. 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 2020, with interest applied, was negative $31,869,646, as shown on row 104 of Exhibit No. 1. The approximate negative $31.9 million represents a refund due to customers in this year's PCA True-up.

Q. To what factors do you attribute the accumulation of the approximate negative $31.9 million deferral balance?

A. The approximate negative $31.9 million deferral balance was primarily driven by unpredictable changes in market energy prices and the resulting variation in forecast prices and actual prices. Because actual market energy prices were lower than expected, it resulted in higher than forecast market power purchases, and alternatively, lower than forecast surplus sales revenue and coal fuel expense.

Last year’s PCA forecast included an average market purchase price of $36.73 per MWh. The actual average market purchase price for the 2019-2020 PCA year was $19.60 per MWh, a 47 percent decrease from the average forecast price. Additionally, last year’s PCA forecast included an average market sales price of $35.84 per MWh. The actual average market sales price was $22.83 per MWh, a 36 percent decrease from the average forecast price. As a result of the difference in forecast and actual market energy prices, market power purchases were higher than forecast while surplus sales revenues were lower than forecast.

As a result of market purchase prices being lower than expected, market power purchase volumes totaled 1,761,557 MWh, which was 1,352,332 MWh, or 330 percent, more than forecast. Consequently, actual market power purchase expense for the 2019-2020 PCA Year was $34,526,427 compared to $14,898,672 included in the forecast, representing a 132 percent increase.

The decrease in actual market energy prices also contributed to lower than forecast surplus sales revenues. Actual surplus sales revenue totaled $50,014,065, which was 22 percent lower than forecast surplus sales revenues of

$64,129,054. Although the value of surplus sales was not as expected, actual surplus sales volumes were higher than forecast. For the 2019-2020 PCA Year surplus sales totaled 2,189,829 MWh, which was 400,432 MWh more than last year's forecast of 1,789,397 MWh, reflecting a 22 percent increase. The increase in surplus sales volumes was also due in part to a 3 percent increase in actual hydro generation compared to forecast.

Actual coal generation totaled 2,342,998 MWh, which was 48 percent lower than forecast, and actual coal fuel expense was $82,407,803, which was approximately 48 percent lower than forecast. Coal-fired generation was displaced with market purchased power as well as natural gas generation. Natural gas generation totaled 2,325,102 MWh for the 2019-2020 PCA Year, which was 383,845 MWh, or 20 percent, higher than forecast. Actual natural gas expense totaled $52,280,833, which was 17 percent higher than forecast.

Finally, the true-up also includes a $2,100,000 water lease expense for the 2019-2020 PCA Year that was not reflected in last year's PCA forecast.

Q. Please explain the water lease the Company entered into in 2019.

A. In 2019, Idaho Power entered into an agreement to purchase water from the Water District 1 supplemental rental pool. The agreement totaled 70,000 acre-feet at a price of $30 per acre foot for a total cost of $2,100,000, as shown on line 26 of Exhibit No. 1. The water flowed through Idaho Power's system beginning at Milner Dam from August 1, 2019, through August 27, 2019.

Q. How did the water lease impact hydro generation?

A. Based on the actual daily water flow, the Company estimated that hydro generation from the water lease totaled 65,937 MWh, resulting in a price of approximately $31.85 per MWh.

Q. Did the water lease expense and associated increase in hydro generation benefit customers?

A. Yes. During the period of flow, daily market energy prices ranged from $25.24 per MWh to $39.55 per MWh during light load hours and from $32.94 per MWh to $54.88 per MWh during heavy load hours. Idaho Power was able to reduce market purchases during this time by using the leased water and running additional water through the Hells Canyon Complex. The purchase of leased water at $31.85 per MWh compared favorably with the average price paid for market purchases during the month, which was approximately $35.79 per MWh.

This additional hydro generation also contributed to Idaho Power's ability to sell into high-priced hours to the benefit of customers. The average price for market sales during the month was $60.70 per MWh, compared to the cost of the leased water at $31.85 per MWh, resulting in net revenue from surplus sales.

Q. Were there any items included in this year's True-up in addition to actual NPSE incurred during the April 2019 through March 2020 period?

A. Yes. Per Commission Order No. 34100, Idaho Power included its actual costs of Western Energy Imbalance Market ("EIM") participation for April 2019 through March 2020 in the True-up. 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 2020 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 2019 through March 2020 PCA deferral under the soft cap of annual CAISO-reported benefits for that same period?

A. Yes. For the April 2019 through March 2020 period, the EIM-related revenue requirement totaled $3.2 million, while CAISO reported EIM benefits for Idaho Power of $20 million from April through December (CAISO's first quarter 2020 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 2019 and March 2020 range between $14 and $18 million (benefits for March 2020 are not yet available). This level of EIM benefits compared to the Idaho-jurisdictional EIM costs of $3.2 million, demonstrates a net benefit to the Company and, ultimately, its customers.

Q. Did the Company calculate the Sales Based Adjustment ("SBA") per the terms of the settlement stipulation approved in Order No. 33307 in Case No. IPC-E-15-15?

A. Yes. The Company's deferral report provided as Exhibit No. 1 reflects the SBA per the methodology approved in Case No. IPC-E-15-15. Beginning on line 10 of Exhibit No. 1, the Company calculates the SBA using actual Idaho jurisdictional billing month sales.

Q. What is this year's True-up of the True-up?

A. This year's True-up of the True-up balance is a credit to customers of $10,778,801, as shown on row 124 of Exhibit No. 1.

Q. What is the combined effect of the True-up and the True-up of the True-up in this year's PCA?

A. The sum of the negative $31.9 million associated with the True-up and the negative $10.8 million associated with the True-up of the True-up represents an approximate $42.7 million credit to customers.

Q. How does this year's combined True-up and the True-up of the True-up compare to last year's amount?

A. The combined True-up and the True-up of the True-up for the last PCA Year was negative $64,031,080, as compared with this year's amount of negative $42,648,447. While this year's true-up reflects a credit to customers, it is less than the credit customers are currently receiving through last year's true-up, and ultimately reflects an increase in billed revenue of $21,382,633.

## III. <u>NET CUSTOMER IMPACT</u>

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, presented in Ms. Blackwell's testimony, to expected customer sales for the June 2020 through May 2021 test year results in a PCA increase of $58.7 million.

## IV. <u>OTHER PCA IMPACT CONSIDERATIONS</u>

Q. Has Idaho Power been monitoring the recent impacts of the current coronavirus disease outbreak?

A. Yes. In February 2020, the World Health Organization ("WHO") designated the novel coronavirus disease outbreak that began in 2019 as COVID-19 ('CO' stands for 'corona,' 'VI' for 'virus,' and 'D' for disease). The infectious disease causes respiratory illness such as fever, cough, and shortness of breath 2-14 days after exposure from another infected person. As of April 14, 2020, WHO reports 1,918,138 confirmed cases and 123,126 confirmed deaths in 213 countries, areas, or territories related to the COVID-19 pandemic.[3]

On March 25, 2020, Idaho Governor Little issued an "extreme emergency declaration" over the COVID-19 outbreak. As permitted by *Idaho Code* § 56-1003(7), on March 25, 2020, Governor Little and the Director of Idaho Department of Health and Welfare issued an Order to Self-Isolate for the State of Idaho ("Stay-Home Order") "to protect the public from the spread of infectious or communicable diseases" through April 15, 2020 or until it is extended, rescinded, superseded, or amended in writing by the Director.[4]

As a result of the impacts of COVID-19 and Idaho's state and local stay-home orders on Idaho businesses, Idaho Power expects that there will be a new subset of its customers

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[3] World Health Organization, Coronavirus disease (COVID-19) pandemic statistics available at https://www.who.int/emergencies/diseases/novel-coronavirus-2019.

[4] Idaho Department of Health & Welfare Director Dave Jeppesen to All Citizens of the State of Idaho, Elected and Appointed Officials, Order to Self-Isolate for the State of Idaho (March 25, 2020).

that will have an inability, or will be challenged financially, to pay their Idaho Power bills until they can return to work.

Q. What is Idaho Power doing to help its customers who may be struggling financially during this difficult time?

A. On March 16, 2020, the Company temporarily suspended service disconnections for non-payment applicable to all Idaho and Oregon residential and small/medium business customers. On the same date, Idaho Power also began a temporary suspension of all late fees for applicable customer billings. In addition, Idaho Power has launched an energy efficiency educational campaign to further educate customers on ways to help them better manage their energy costs. The Company hopes that these measures will help contribute to the overall health and safety of customers during this unprecedented crisis, as well as to mitigate the short-term financial impact for affected customers.

Q. Did Idaho Power consider recommending some form of mitigation measures for this year's PCA in light of this ongoing COVID-19 event?

A. Yes. However, after thoughtful and careful consideration, Idaho Power believes its customers would be best served by implementing the full proposed PCA revenue increase effective June 1, 2020. While the Company is sensitive to the financial impact this proposed rate increase will have on its customers during this challenging time, the potential longer-term downside risks outweigh the near-term relief of deferring a portion, or all, of the requested increase.

First, Idaho Power believes that postponing collection of known costs to a future period could create more harm than good by risking the compounding or "pancaking" of this current revenue increase on top of possible future rate increases. Secondly, the Company believes that revenue collection less than the proposed collection in this case could have significant negative financial impact on the Company.

**A. Rate Pancaking Concerns**

Q. Please explain the Company's concern regarding the risk of "rate pancaking" associated with the deferral of the proposed PCA increase?

A. Idaho Power believes that customers interests are generally best served by matching cost recovery as closely as possible with the period in which power supply costs are incurred. This matching minimizes compounding or pancaking of rates that could harm customers more in the future than a deferral would help those same customers today.

Q. Are there certain aspects of this year's PCA request that should be considered when evaluating the rate pancaking risk in this case?

A. Yes. As I mentioned earlier in my testimony, this year's PCA increase, if approved, would move the level of PCA cost recovery back to a level that reflects a more normal expectation of NPSE. As can be seen in Table 2, PCA collection in each of the years preceding last year's PCA were either near or above the level of collection proposed in this case. Because the vast majority of this year's PCA increase is the result of removing non-recurring benefits (i.e., relatively high market energy prices, revenue sharing, and temporary tax reform benefits), the risk of rate pancaking from deferred cost recovery is quite high.

It should also be noted that this year's PCA forecast includes a slightly above normal level of hydro generation as compared to the 30-year median value. If hydro conditions were to worsen next year, any deferred collection from this PCA-year would add to the resulting higher NPSE next year. Further, approximately 51 percent of the proposed PCA forecast collection is related to recovery of PURPA costs - costs that are known today and are under contract. Deferral of known annual PURPA costs would surely result in compounding with future known PURPA cost collection.

Q. Has the Commission in the past expressed concerns about deferring PCA recovery into future periods?

A. Yes. The Commission has, on a number of occasions, expressed opposition to spreading the collection of PCA amounts over multiple years. As part of its order regarding the 2001 PCA, the Commission made the following statement:

> While the Commission is sympathetic to the request that the authorized rate increase or some portion thereof be amortized over time, the Commission declines to adopt this recommendation.

Order No. 28722 at 26. As part of its order regarding the 2002 PCA, the Commission made the following statement:

> The Commission is also concerned that the longer the power supply cost recovery is delayed, the greater the risk that the customers taking service when deferred costs were incurred will not be the same customers that will later pay for them.

Order No. 29026 at 15. As part of its order regarding the 2008 PCA, the Commission made the following statement:

> It is simply too risky, and potentially compounds the problem, to seek recovery from ratepayers across three future years.

Order No. 30563 at 7. As part of its order regarding the 2009 PCA, the Commission made the following statement:

> Despite the significant amount included for recovery in the PCA this year, the Commission declines to spread recovery of the amount into a subsequent year.

Order No. 30828 at 10. Most recently, as part of its order regarding the 2013 PCA, the Commission made the following statement:

> The PCA was never intended for long term recovery of costs that continue

> year to year. It was implemented to properly recover the Company's annual fluctuation in power supply costs and keep the customers from paying either too little or too much of those costs.

Order No. 32821 at 11.

**B. <u>COVID-19 Financial Impacts</u>**

Q. If the Commission were to defer collection of some, or all, of the requested PCA increase, would the Company have financial concerns?

A. Yes. Under normal circumstances deferred PCA collection of the amount requested in this case would not likely have a material financial impact on the Company. However, shortly following the announcement of the COVID-19 outbreak in the United States, the resulting negative impacts on the financial markets have presented challenges for companies like Idaho Power. Reduced cash from PCA-related sales would further challenge the Company's ability to cost-effectively fund its near-term operations. If PCA collection were to be deferred, the Company may not be able to cost-effectively access financial markets to offset the lost cash in the near term.

Q. Please provide some examples of how the COVID-19 crisis has impacted the Company's financing costs and its ability to access cash to fund operations.

A. Idaho Power began 2020 with a solid short-term cash investing position; its short-term investments were liquid and accessible. By the end of the first quarter of 2020 that all changed, despite efforts to conserve cash.

The uncertain economic impact of COVID-19 on the cash forecast for the remainder of the year compelled Idaho Power to explore the possibility of short-term borrowing in March and April.

The Company typically issues commercial paper ("CP") for short-term borrowing; however, the market in March for CP was negatively impacted by the current crisis and did not represent a reliable option to finance short-term debt. At the same time, economic concerns tied to COVID-19 caused a surge of investors exiting money market funds to raise cash during mid to late March. This caused short-term rates to rise steeply as there were many sellers and few buyers.

This unusual financial market turbulence had a particularly troubling impact on two Idaho Power-issued bonds with rates that reset weekly: the American Falls guarantee and the Port of Morrow Pollution Control Revenue Bonds. The aggregate principal amount outstanding for these two bonds is over 24 million dollars. The interest rates on these bonds went from 1.35 percent on March 11 to 4.2 percent on March 19, and then increased to 5.2 percent on March 25. The financial market has recently stabilized somewhat with rates coming down to 2.15 percent on April

1. If rates were to stay at the 5 percent level, it would cost the Company over $800,000 in additional annual interest expense. There would also be a high risk that the Company could be forced to buy back the bonds if there were not buyers in the market.

Several of the Company's banks had previously expressed interest in providing an 18-month to three-year loan to the Company at relatively favorable rates. The Company had a call with one of those banks the morning of March 23 to work through the details of the loan. By the afternoon of March 23, the bank pulled back its offer. The Company contacted all six banks that it normally transacts with and none were willing to execute a similar loan.

Q. What measures has the Company taken to ensure its ability to fund operations in response to these unique financial circumstances?

A. During the last week of March, the investment grade bond market presented some relatively favorable financing opportunities. The Company quickly moved a 30-year debt issuance planned for later in the year up to March 31st, to take advantage of favorable long-term rates. Idaho Power also increased the size of the proceeds received on its bonds to $260 million from the $220 million that was originally planned, to provide extra security as the Company continues to evaluate the unknown impacts of

COVID-19, including reduced revenue collections from customers. A large portion of the proceeds are earmarked for redemption of $100 million of bonds that mature later in the year. Additionally, the Company is currently making best efforts to keep its $300 million credit line in reserve for the future. On March 23, Idaho Power inquired of the availability of the $300 million credit line and was assured the Company would continue to be allowed to draw on the credit line.

Q. Please summarize the Company's concerns regarding the financial impact to Idaho Power of deferring the proposed PCA collection to a subsequent period.

A. The financial impact of the COVID-19 health crisis on the CP market has already been felt by the Company. While Idaho Power has been able to successfully navigate financial market impacts to-date, further financial stress caused by deferred PCA cost recovery would likely exacerbate an already challenging operating environment.

## V. CONCLUSION

Q. Please summarize the Company's request in this case.

A. The PCA is a rate mechanism that quantifies and tracks annual differences between actual NPSE and the normalized level of NPSE recovered in the Company's base rates, resulting in a credit or surcharge that is updated annually on June 1. The calculation of the proposed 2020-2021 PCA rates complies with the methodology that was approved in Order Nos. 30715, 33149, and 33307. If approved, the 2020-2021 PCA will result in an increase in total billed revenue of approximately $58.7 million, or 5.21 percent.

While the Company is sensitive to the financial impact this proposed rate increase will have on its customers during this challenging time, the potential longer-term downside risks outweigh the near-term relief of deferring a portion, or all, of the requested increase. After thoughtful and careful consideration, Idaho Power believes its customers would be best served by implementing the full proposed PCA revenue increase effective June 1, 2020.

Q. Does this conclude your testimony?

A. Yes, it does.

**DECLARATION OF TIMOTHY E. TATUM**

I, Timothy E. Tatum, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Timothy E. Tatum. I am employed by Idaho Power Company as the Vice President of the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit No. 1 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 15th day of April 2020, at Boise, Idaho.

Signed: Tim Tatum ______________________
Timothy E. Tatum

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-20-21

IDAHO POWER COMPANY

# TATUM, DI TESTIMONY

# EXHIBIT NO. 1

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Power Cost Adjustment** | | | | | | | | | | | | | | | | |
| 2 | **April 2019 thru March 2020** | | | | | | | | | | | | | | | | |
| 3 | | | | | April | May | June | July | August | September | October | November | December | January | February | March | Totals |
| 4 | **PCA Forecasted Revenues** | *Prior* | *New (Effective 6/1/19)* | | | | | | | | | | | | | | |
| 5 | Actual Idaho Jurisdictional Billing Month Sales | | | Mwh | 969,133 | 1,009,175 | 1,087,846 | 1,453,791 | 1,555,867 | 1,369,800 | 1,012,013 | 1,000,525 | 1,087,235 | 1,156,543 | 1,101,758 | 1,024,103 | 13,827,789 |
| 6 | % of Prior Period Billings at Old Rate | | | | 100.000% | 100.000% | 56.230% | 0.005% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | |
| 7 | % of Current Period Billings at New Rate | | | | 0.000% | 0.000% | 43.770% | 99.995% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | |
| 8 | **Forecasted Billing Month Revenues** | $ 6.315 | $ 5.836 | $ | (6,120,074.33) | (6,372,942.55) | (6,671,781.12) | (8,508,333.42) | (9,080,039.91) | (7,994,151.95) | (5,906,107.25) | (5,839,062.56) | (6,345,100.82) | (6,749,586.39) | (6,429,862.57) | (5,976,663.09) | (81,993,705.96) |
| 9 | | | | | | | | | | | | | | | | | |
| 10 | **Sales Based Adjustment** | | *(Effective 6/1/15)* | | | | | | | | | | | | | | |
| 11 | Actual Idaho Jurisdictional Billing Month Sales | | | Mwh | 969,133 | 1,009,175 | 1,087,846 | 1,453,791 | 1,555,867 | 1,369,800 | 1,012,013 | 1,000,525 | 1,087,235 | 1,156,543 | 1,101,758 | 1,024,103 | 13,827,789 |
| 12 | Normalized Idaho Jurisdictional Billing Month Sales | | | Mwh | 947,192 | 953,286 | 1,131,686 | 1,370,142 | 1,428,766 | 1,300,608 | 1,045,495 | 957,864 | 1,081,014 | 1,177,663 | 1,101,149 | 1,004,027 | 13,498,892 |
| 13 | Sales Change | | | Mwh | 21,941 | 55,889 | (43,840) | 83,649 | 127,101 | 69,192 | (33,482) | 42,661 | 6,221 | (21,120) | 609 | 20,076 | 328,897 |
| 14 | % of Prior Period Billings at Old Rate | | | | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | |
| 15 | % of Current Period Billings at New Rate | | | | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | 100.000% | |
| 16 | Sales Adjustment Prior To Sharing | | $ 26.72 | $ | (586,263.52) | (1,493,354.08) | 1,171,404.80 | (2,235,101.28) | (3,396,138.72) | (1,848,810.24) | 894,639.04 | (1,139,901.92) | (166,225.12) | 564,326.40 | (16,272.48) | (536,430.72) | (8,788,127.84) |
| 17 | Sharing Percentage | | | | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | |
| 18 | **Sales Based Adjustment** | | | $ | (556,950.34) | (1,418,686.38) | 1,112,834.56 | (2,123,346.22) | (3,226,331.78) | (1,756,369.73) | 849,907.09 | (1,082,906.82) | (157,913.86) | 536,110.08 | (15,458.86) | (509,609.18) | (8,348,721.44) |
| 19 | | | | | | | | | | | | | | | | | |
| 20 | **Actual Non-QF** | | | | | | | | | | | | | | | | |
| 21 | Fuel Expense-Coal | | | $ | 6,285,161.98 | 4,237,536.91 | 6,164,540.47 | 9,583,663.77 | 10,273,347.98 | 7,452,239.59 | 8,205,308.64 | 6,982,744.56 | 7,449,100.48 | 5,970,738.10 | 4,969,948.43 | 4,833,471.95 | 82,407,802.86 |
| 22 | Fuel Expense-Gas | | | $ | 704,600.74 | 933,792.62 | 2,416,082.40 | 6,341,963.37 | 8,616,829.95 | 4,526,682.20 | 2,549,992.21 | 5,368,173.84 | 6,655,722.62 | 7,034,103.74 | 4,541,462.58 | 2,591,426.75 | 52,280,833.02 |
| 23 | Non-Firm Purchases | | | $ | 2,518,925.04 | 3,179,352.81 | 4,151,646.42 | 8,176,059.25 | 9,249,432.31 | 7,622,299.24 | 7,420,748.01 | 8,121,682.46 | 9,110,214.51 | 7,379,995.44 | 5,895,248.95 | 3,447,758.72 | 76,273,363.16 |
| 24 | Third Party Transmission | | | $ | 116,386.00 | 133,285.00 | 463,458.55 | 414,479.87 | 456,226.03 | 273,272.30 | 276,525.24 | 314,381.31 | 24,815.74 | 193,711.50 | 231,186.00 | 136,204.00 | 3,033,931.54 |
| 25 | Surplus Sales | | | $ | (9,042,970.90) | (3,198,100.10) | (4,330,434.90) | (2,037,183.49) | (5,997,405.55) | (8,436,682.14) | (2,496,580.22) | (2,587,737.42) | (3,868,159.18) | (1,582,442.41) | (2,992,811.68) | (3,443,557.34) | (50,014,065.33) |
| 26 | Water for Power (Leases) | | | $ | - | - | - | - | 2,100,000.00 | - | - | - | - | - | - | - | 2,100,000.00 |
| 27 | Total Actual Non-QF | | | $ | 582,102.86 | 5,285,867.24 | 8,865,292.94 | 22,478,982.77 | 24,698,430.72 | 11,437,811.19 | 15,955,993.88 | 18,199,244.75 | 19,371,694.17 | 18,996,106.37 | 12,645,034.28 | 7,565,304.08 | 166,081,865.25 |
| 28 | Idaho Allocation | | | | 95.2% | 95.3% | 95.4% | 95.6% | 95.8% | 95.8% | 95.5% | 94.9% | 94.9% | 95.3% | 95.9% | 95.5% | |
| 29 | Net Idaho Jurisdictional Actual Non-QF | | | $ | 554,161.92 | 5,037,431.48 | 8,457,489.46 | 21,489,907.53 | 23,661,096.63 | 10,957,423.12 | 15,237,974.16 | 17,271,083.27 | 18,383,737.77 | 18,103,289.37 | 12,126,587.87 | 7,224,865.40 | 158,505,047.98 |
| 30 | | | | | | | | | | | | | | | | | |
| 31 | **Base Non-QF** | | | | | | | | | | | | | | | | |
| 32 | Fuel Expense-Coal | | | $ | 7,525,242.00 | 7,487,643.00 | 9,019,153.00 | 11,385,255.00 | 12,185,412.00 | 10,796,845.00 | 7,781,442.00 | 7,302,324.00 | 8,455,019.00 | 9,553,773.00 | 8,912,994.00 | 8,098,078.00 | 108,503,180.00 |
| 33 | Fuel Expense-Gas | | | $ | 2,314,209.00 | 2,302,646.00 | 2,773,625.00 | 3,501,263.00 | 3,747,333.00 | 3,320,312.00 | 2,392,997.00 | 2,245,656.00 | 2,600,139.00 | 2,938,035.00 | 2,740,979.00 | 2,490,369.00 | 33,367,563.00 |
| 34 | Non-Firm Purchases | | | $ | 4,342,083.00 | 4,320,388.00 | 5,204,073.00 | 6,569,319.00 | 7,031,012.00 | 6,229,805.00 | 4,489,910.00 | 4,213,459.00 | 4,878,566.00 | 5,512,549.00 | 5,142,819.00 | 4,672,610.00 | 62,606,593.00 |
| 35 | Third Party Transmission | | | $ | 378,398.00 | 376,507.00 | 453,517.00 | 572,494.00 | 612,729.00 | 542,907.00 | 391,281.00 | 367,189.00 | 425,151.00 | 480,400.00 | 448,179.00 | 407,203.00 | 5,455,955.00 |
| 36 | Surplus Sales | | | $ | (3,588,093.00) | (3,570,166.00) | (4,300,402.00) | (5,428,577.00) | (5,810,099.00) | (5,148,019.00) | (3,710,251.00) | (3,481,805.00) | (4,031,418.00) | (4,555,312.00) | (4,249,784.00) | (3,861,227.00) | (51,735,153.00) |
| 37 | Water for Power (Leases) | | | $ | 165,106.00 | 164,281.00 | 197,883.00 | 249,796.00 | 267,352.00 | 236,886.00 | 170,727.00 | 160,216.00 | 185,506.00 | 209,613.00 | 195,555.00 | 177,676.00 | 2,380,597.00 |
| 38 | Net 95% Items | | | $ | 11,136,945.00 | 11,081,299.00 | 13,347,849.00 | 16,849,550.00 | 18,033,739.00 | 15,978,736.00 | 11,516,106.00 | 10,807,039.00 | 12,512,963.00 | 14,139,058.00 | 13,190,742.00 | 11,984,709.00 | 160,578,735.00 |
| 39 | Idaho Allocation | | | | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | |
| 40 | Net Idaho Jurisdiction 95% Items | | | $ | 10,580,097.75 | 10,527,234.05 | 12,680,456.55 | 16,007,072.50 | 17,132,052.05 | 15,179,799.20 | 10,940,300.70 | 10,266,687.05 | 11,887,314.85 | 13,432,105.10 | 12,531,204.90 | 11,385,473.55 | 152,549,798.25 |
| 41 | | | | | | | | | | | | | | | | | |
| 42 | Idaho Jurisdiction Change From Base | | | $ | (10,025,935.83) | (5,489,802.57) | (4,222,967.09) | 5,482,835.03 | 6,529,044.58 | (4,222,376.08) | 4,297,673.46 | 7,004,396.22 | 6,496,422.92 | 4,671,184.27 | (404,617.03) | (4,160,608.15) | 5,955,249.73 |
| 43 | Sharing Percentage | | | | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | |
| 44 | **Net Power Supply Costs Deferral** | | | $ | (9,524,639.04) | (5,215,312.44) | (4,011,818.74) | 5,208,693.28 | 6,202,592.35 | (4,011,257.28) | 4,082,789.79 | 6,654,176.41 | 6,171,601.77 | 4,437,625.06 | (384,386.18) | (3,952,577.74) | 5,657,487.24 |
| 45 | | | | | | | | | | | | | | | | | |
| 46 | **Emission Allowance and REC Sales** | | | | | | | | | | | | | | | | |
| 47 | Emission Allowance Sales Credit | | | $ | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 48 | Renewable Energy Credit Sales | | | $ | (772,801.94) | 1,170.04 | (602,090.48) | (266,352.12) | (13,874.17) | 221.57 | (407,882.96) | (373,467.18) | (176,032.56) | (289,502.21) | (1,841,141.42) | (667,163.20) | (5,408,916.63) |
| 49 | Total Emission Allowances and REC Sales | | | $ | (772,801.94) | 1,170.04 | (602,090.48) | (266,352.12) | (13,874.17) | 221.57 | (407,882.96) | (373,467.18) | (176,032.56) | (289,502.21) | (1,841,141.42) | (667,163.20) | (5,408,916.63) |
| 50 | Idaho Allocation | | | | 95.2% | 95.3% | 95.4% | 95.6% | 95.8% | 95.8% | 95.5% | 94.9% | 94.9% | 95.3% | 95.9% | 95.5% | |
| 51 | Sharing Percentage | | | | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | |
| 52 | **Net Emission Allowances and REC Sales** | | | $ | (698,922.07) | 1,059.30 | (545,674.60) | (241,901.00) | (12,626.88) | 201.65 | (370,051.82) | (336,699.34) | (158,702.15) | (262,100.83) | (1,677,371.89) | (605,283.81) | (4,908,073.44) |
| 53 | | | | | | | | | | | | | | | | | |
| 54 | **Idaho Allocated EIM Participation Costs** | | | | | | | | | | | | | | | | |
| 55 | Return on EIM Capital Investment | | | $ | 59,016.31 | 58,721.65 | 60,691.06 | 59,114.47 | 58,206.63 | 57,301.63 | 56,394.21 | 55,486.37 | 54,581.53 | 54,203.64 | 53,353.52 | 52,436.43 | 679,507.44 |
| 56 | Operating Expenses | | | $ | 219,091.04 | 209,248.07 | 207,365.67 | 204,249.57 | 219,189.81 | 239,071.19 | 202,864.57 | 318,318.96 | 226,735.14 | 193,418.44 | 203,528.94 | 227,840.88 | 2,670,922.28 |
| 57 | Total | | | $ | 278,107.35 | 267,969.72 | 268,056.72 | 263,364.04 | 277,396.44 | 296,372.82 | 259,258.79 | 373,805.33 | 281,316.67 | 247,622.08 | 256,882.46 | 280,277.31 | 3,350,429.73 |
| 58 | Sharing Percentage | | | | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | |
| 59 | **EIM Participation Costs** | | | $ | 264,201.98 | 254,571.24 | 254,653.89 | 250,195.84 | 263,526.62 | 281,554.18 | 246,295.85 | 355,115.06 | 267,250.84 | 235,240.98 | 244,038.34 | 266,263.45 | 3,182,908.27 |
| 60 | | | | | | | | | | | | | | | | | |
| 61 | **Demand Response Incentive Payments** | | | | | | | | | | | | | | | | |
| 62 | Actual | | | $ | 0.00 | 0.00 | 230,610.45 | 2,743,650.94 | 3,399,435.42 | 615,524.03 | 7,014.87 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 6,996,235.71 |
| 63 | Base | | | $ | 780,401.00 | 776,502.00 | 935,327.00 | 1,180,702.00 | 1,263,682.00 | 1,119,681.00 | 806,970.00 | 757,284.00 | 876,823.00 | 990,769.00 | 924,317.00 | 839,807.00 | 11,252,265.00 |
| 64 | Change From Base | | | $ | (780,401.00) | (776,502.00) | (704,716.55) | 1,562,948.94 | 2,135,753.42 | (504,156.97) | (799,955.13) | (757,284.00) | (876,823.00) | (990,769.00) | (924,317.00) | (839,807.00) | (4,256,029.29) |
| 65 | Idaho Allocation | | | | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | |
| 66 | Sharing Percentage | | | | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | |
| 67 | **Demand Response Incentive Payment Deferral** | | | $ | (780,401.00) | (776,502.00) | (704,716.55) | 1,562,948.94 | 2,135,753.42 | (504,156.97) | (799,955.13) | (757,284.00) | (876,823.00) | (990,769.00) | (924,317.00) | (839,807.00) | (4,256,029.29) |
| 68 | | | | | | | | | | | | | | | | | |
| 69 | **Actual QF** | | | | | | | | | | | | | | | | |
| 70 | Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages) | | | $ | 14,084,693.57 | 13,110,644.53 | 20,073,693.68 | 21,258,694.38 | 21,191,593.25 | 16,117,024.46 | 16,467,275.58 | 13,357,523.78 | 15,653,703.85 | 15,132,554.70 | 16,971,776.43 | 11,812,563.64 | 195,231,741.85 |
| 71 | Idaho Allocation | | | | 95.2% | 95.3% | 95.4% | 95.6% | 95.8% | 95.8% | 95.5% | 94.9% | 94.9% | 95.3% | 95.9% | 95.5% | |
| 72 | Idaho Jurisdictional Actual QF | | | $ | 13,408,628.28 | 12,494,444.24 | 19,150,303.77 | 20,323,311.83 | 20,301,546.33 | 15,440,109.43 | 15,726,248.18 | 12,676,290.07 | 14,855,364.95 | 14,421,324.63 | 16,275,933.60 | 11,280,998.28 | 186,354,503.59 |
| 73 | | | | | | | | | | | | | | | | | |
| 74 | **Base QF** | | | $ | 9,283,440.00 | 9,237,057.00 | 11,126,388.00 | 14,045,307.00 | 15,032,413.00 | 13,319,420.00 | 9,599,498.00 | 9,008,440.00 | 10,430,450.00 | 11,785,917.00 | 10,995,427.00 | 9,990,113.00 | 133,853,870.00 |
| 75 | Idaho Allocation | | | | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | |
| 76 | Idaho Jurisdictional Base | | | $ | 8,819,268.00 | 8,775,204.15 | 10,570,068.60 | 13,343,041.65 | 14,280,792.35 | 12,653,449.00 | 9,119,523.10 | 8,558,018.00 | 9,908,927.50 | 11,196,621.15 | 10,445,655.65 | 9,490,607.35 | 127,161,176.50 |
| 77 | | | | | | | | | | | | | | | | | |
| 78 | Idaho Jurisdiction Change From Base | | | $ | 4,589,360.28 | 3,719,240.09 | 8,580,235.17 | 6,980,270.18 | 6,020,753.98 | 2,786,660.43 | 6,606,725.08 | 4,118,272.07 | 4,946,437.45 | 3,224,703.48 | 5,830,277.95 | 1,790,390.93 | 59,193,327.09 |
| 79 | Sharing Percentage | | | | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | |
| 80 | **QF Deferral** | | | $ | 4,589,360.28 | 3,719,240.09 | 8,580,235.17 | 6,980,270.18 | 6,020,753.98 | 2,786,660.43 | 6,606,725.08 | 4,118,272.07 | 4,946,437.45 | 3,224,703.48 | 5,830,277.95 | 1,790,390.93 | 59,193,327.09 |
| 81 | | | | | | | | | | | | | | | | | |

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Power Cost Adjustment** | | | | | | | | | | | | | | | | |
| 2 | **April 2019 thru March 2020** | | | | | | | | | | | | | | | | |
| 3 | | | | | April | May | June | July | August | September | October | November | December | January | February | March | Totals |
| 82 | | | | | | | | | | | | | | | | | |
| 83 | **Total Deferral** | | | $ | (12,827,424.52) | (9,808,572.74) | (1,986,267.39) | 3,128,527.60 | 2,303,627.80 | (11,197,519.67) | 4,709,603.61 | 3,111,610.82 | 3,846,750.23 | 431,223.38 | (3,357,080.21) | (9,827,286.44) | (31,472,807.53) |
| 84 | | | | | | | | | | | | | | | | | |
| 85 | **True-Up Summary:** | | | | | | | | | | | | | | | | |
| 86 | Principal Balances | | | | | | | | | | | | | | | | |
| 87 | | | | | | | | | | | | | | | | | |
| 88 | Beginning True-Up Balance | | | $ | 0.00 | (12,827,424.52) | (22,635,997.26) | (24,622,264.65) | (21,493,737.05) | (19,190,109.25) | (30,387,628.92) | (25,678,025.31) | (22,566,414.49) | (18,719,664.26) | (18,288,440.88) | (21,645,521.09) | 0.00 |
| 89 | | | | | | | | | | | | | | | | | |
| 90 | Amount Deferred | | | $ | (12,827,424.52) | (9,808,572.74) | (1,986,267.39) | 3,128,527.60 | 2,303,627.80 | (11,197,519.67) | 4,709,603.61 | 3,111,610.82 | 3,846,750.23 | 431,223.38 | (3,357,080.21) | (9,827,286.44) | (31,472,807.53) |
| 91 | | | | | | | | | | | | | | | | | |
| 92 | Ending Balance | | | $ | (12,827,424.52) | (22,635,997.26) | (24,622,264.65) | (21,493,737.05) | (19,190,109.25) | (30,387,628.92) | (25,678,025.31) | (22,566,414.49) | (18,719,664.26) | (18,288,440.88) | (21,645,521.09) | (31,472,807.53) | (31,472,807.53) |
| 93 | | | | | | | | | | | | | | | | | |
| 94 | Interest Balances | | | | | | | | | | | | | | | | |
| 95 | | | | | | | | | | | | | | | | | |
| 96 | Accrual thru Prior Month | | | $ | 0.00 | 0.00 | (21,383.32) | (59,117.53) | (100,162.85) | (135,992.91) | (167,982.82) | (218,639.00) | (261,444.27) | (299,062.48) | (330,268.16) | (360,754.99) | |
| 97 | | | | | | | | | | | | | | | | | |
| 98 | Monthly Interest Rate (Annual 2% for 2019) | | | | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | |
| 99 | | | | | | | | | | | | | | | | | |
| 100 | Monthly Interest Inc/(Exp) | | | $ | 0.00 | (21,383.32) | (37,734.21) | (41,045.32) | (35,830.06) | (31,989.91) | (50,656.18) | (42,805.27) | (37,618.21) | (31,205.68) | (30,486.83) | (36,083.08) | (396,838.07) |
| 101 | | | | | | | | | | | | | | | | | |
| 102 | Interest Accrued to date | | | $ | 0.00 | (21,383.32) | (59,117.53) | (100,162.85) | (135,992.91) | (167,982.82) | (218,639.00) | (261,444.27) | (299,062.48) | (330,268.16) | (360,754.99) | (396,838.07) | (396,838.07) |
| 103 | | | | | | | | | | | | | | | | | |
| 104 | **Ending True-Up Balance** | | | $ | (12,827,424.52) | (22,657,380.58) | (24,681,382.18) | (21,593,899.90) | (19,326,102.16) | (30,555,611.74) | (25,896,664.31) | (22,827,858.76) | (19,018,726.74) | (18,618,709.04) | (22,006,276.08) | (31,869,645.60) | (31,869,645.60) |
| 105 | | | | | | | | | | | | | | | | | |
| 106 | | | | | | | | | | | | | | | | | |
| 107 | **True-Up of the True-Up Summary:** | | | | | | | | | | | | | | | | |
| 108 | Beginning Balance True-Up of True-Up | | | $ | (10,097,124.25) | (62,434,285.31) | (60,764,417.05) | (62,688,108.62) | (55,704,949.67) | (48,222,655.42) | (41,634,484.01) | (36,752,986.94) | (31,919,825.82) | (26,658,040.13) | (21,070,311.22) | (15,739,953.86) | (10,097,124.25) |
| 109 | Adjustments: | | | | | | | | | | | | | | | | |
| 110 | Revenue Sharing | | | $ | | | (5,068,654.42) | | | | | | | | | | (5,068,654.42) |
| 111 | DSM Rider Forecasted Surplus Funds Order No. | | | $ | | | | | | | | | | | | | - |
| 112 | 2018-19 PCA trnsfr per IPUC Ord No. 34351 | | | $ | (53,933,955.60) | | | | | | | | | | | | (53,933,955.60) |
| 113 | | | | | | | | | | | | | | | | | - |
| 114 | True-Up of True-Up Balance | | | $ | (64,031,079.85) | (62,434,285.31) | (65,833,071.47) | (62,688,108.62) | (55,704,949.67) | (48,222,655.42) | (41,634,484.01) | (36,752,986.94) | (31,919,825.82) | (26,658,040.13) | (21,070,311.22) | (15,739,953.86) | (69,099,734.27) |
| 115 | | | | | | | | | | | | | | | | | |
| 116 | Monthly Interest Rate (Annual 2% for 2019) | | | | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | 0.1667% | |
| 117 | | | | | | | | | | | | | | | | | |
| 118 | Monthly Interest | | | $ | (106,739.81) | (104,077.95) | (109,743.73) | (104,501.08) | (92,860.15) | (80,387.17) | (69,404.68) | (61,267.23) | (53,210.35) | (44,438.95) | (35,124.21) | (26,238.50) | (887,993.81) |
| 119 | | | | | | | | | | | | | | | | | |
| 120 | True-Up of True-Up Including Interest | | | $ | (64,137,819.66) | (62,538,363.26) | (65,942,815.20) | (62,792,609.70) | (55,797,809.82) | (48,303,042.59) | (41,703,888.69) | (36,814,254.17) | (31,973,036.17) | (26,702,479.08) | (21,105,435.43) | (15,766,192.36) | (69,987,728.08) |
| 121 | | | | | | | | | | | | | | | | | |
| 122 | Monthly Collection Applied To Balance | | | $ | 1,703,534.35 | 1,773,946.21 | 3,254,706.58 | 7,087,660.03 | 7,575,154.40 | 6,668,558.58 | 4,950,901.75 | 4,894,428.35 | 5,314,996.04 | 5,632,167.86 | 5,365,481.57 | 4,987,391.28 | 59,208,927.00 |
| 123 | | | | | | | | | | | | | | | | | |
| 124 | **Ending True-Up of the True-Up Balance** | | | $ | (62,434,285.31) | (60,764,417.05) | (62,688,108.62) | (55,704,949.67) | (48,222,655.42) | (41,634,484.01) | (36,752,986.94) | (31,919,825.82) | (26,658,040.13) | (21,070,311.22) | (15,739,953.86) | (10,778,801.08) | (10,778,801.08) |
| 125 | | | | | | | | | | | | | | | | | |
| 126 | | | | | | | | | | | | | | | | | |
| 127 | | | | | | | | | | | | | | | | | |
| 128 | | | | | | | | | | | | | | | | | |
| 129 | | | | | | | | | | | | | | | | | |
| 130 | Idaho Billed Sales | | | Mwh | 969,133 | 1,009,175 | 1,087,846 | 1,453,791 | 1,555,867 | 1,369,800 | 1,012,013 | 1,000,525 | 1,087,235 | 1,156,543 | 1,101,758 | 1,024,103 | 13,827,789 |
| 131 | Oregon Billed Sales | | | Mwh | 49,111 | 49,305 | 52,566 | 67,027 | 68,435 | 60,239 | 47,642 | 53,680 | 57,860 | 57,555 | 46,966 | 48,719 | 659,105 |
| 132 | Total | | | Mwh | 1,018,244 | 1,058,480 | 1,140,412 | 1,520,818 | 1,624,302 | 1,430,039 | 1,059,655 | 1,054,205 | 1,145,095 | 1,214,098 | 1,148,724 | 1,072,822 | 14,486,894 |
| 133 | Idaho % Billed Sales | | | | 95.2% | 95.3% | 95.4% | 95.6% | 95.8% | 95.8% | 95.5% | 94.9% | 94.9% | 95.3% | 95.9% | 95.5% | |
| 134 | Oregon % Billed Sales | | | | 4.8% | 4.7% | 4.6% | 4.4% | 4.2% | 4.2% | 4.5% | 5.1% | 5.1% | 4.7% | 4.1% | 4.5% | |
| 135 | | | | | | | | | | | | | | | | | |
| 136 | | | | | | | | | | | | | | | | | |
| 137 | | | | | | | | | | | | | | | | | |