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March 24, 2017

VIA ELECTRONIC

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: Docket No. UE 314 - In the Matter of the Application of IDAHO POWER COMPANY 2017 Annual Power Cost Update.

Attention Filing Center:

Attached for filing in the above-referenced docket is an electronic copy of Idaho Power Company's March Forecast - Direct Testimony of Nicole A. Blackwell. The workpapers and supporting documents for the 2017 March Forecast will be provided to Staff and CUB within five business days of the filing of the March Forecast. Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 314

IN THE MATTER OF IDAHO POWER COMPANY'S 2017 ANNUAL POWER COST UPDATE	)
	)
MARCH FORECAST	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

NICOLE A. BLACKWELL

March 24, 2017

Q. Are you the same Nicole A. Blackwell who previously submitted testimony in this proceeding?

A. Yes. I previously submitted direct and reply testimony in this proceeding regarding the October Update for the 2017 Annual Power Cost Update ("APCU"). The 2017 October Update is Idaho Power Company's ("Idaho Power" or "Company") estimate of what "normalized" power supply expenses will be for the upcoming APCU test period of April 2017 through March 2018.

Q. What is the status of the October Update in this proceeding?

A. The Company filed the 2017 October Update on October 28, 2016, and Public Utility Commission of Oregon ("Commission") Staff ("Staff") and the Citizens' Utility Board of Oregon ("CUB") reviewed the filing. Several rounds of discovery requests have been served on the Company since the initial filing. The parties held a settlement conference and workshop on January 12, 2017.

On January 31, 2017, Staff filed opening testimony and CUB indicated that they would not be filing opening testimony. On February 16, 2017, the parties held a second settlement conference. Although the parties were unable to reach settlement, from the Company's perspective, the settlement conference was useful to allow it to better understand and respond to the parties' positions and concerns.

On March 3, 2017, the Company filed reply testimony in response to issues raised by Staff in opening testimony. The Company also hosted a workshop on March 6, 2017, to discuss unresolved issues with parties.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the second part of the Company's APCU filing, which is the March Forecast, as detailed in Order No. 08-238.[1] As mentioned

[1] *Re Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism*, Docket No. UE 195, Order No. 08-238 (Apr. 28, 2008).

previously, the Company filed the first part of the APCU, the October Update, on October 28, 2016. The initial October Update filing proposed a revenue increase of approximately $1.5 million, or 2.64 percent. If the March Forecast is approved, the 2017 composite APCU (both the October Update and March Forecast components) will result in a revenue increase of approximately $0.6 million, or 1.08 percent, to become effective June 1, 2017.

Q. How is your testimony organized?

A. My testimony begins by describing the filing requirements associated with the March Forecast and the differences between the October Update and the March Forecast. Next, my testimony describes the required updates to the AURORAxmp Electric Market Model ("AURORA"). I then present and discuss the forecast of total net power supply expenses ("NPSE") for the 2017 March Forecast and how it compares to last year's 2016 March Forecast. My testimony concludes with the quantification of the projected revenue deficiency and the proposed rate implementation to eliminate that deficiency.

Q. Have you prepared exhibits for this proceeding?

A. Yes, I am sponsoring the following exhibits:

1. Exhibit 301, Forward Price Curves used for re-pricing purchased power and surplus sales.
2. Exhibit 302, determination of expected NPSE for the 2017 March Forecast.
3. Exhibit 303, October Update and March Forecast combined rate calculation.
4. Exhibit 304, Revenue Spread.
5. Exhibit 305, Calculation of Revenue Impact.

March Forecast Overview

Q. What is the March Forecast?

A. The March Forecast is the Company's quantification of the "expected" NPSE for the APCU test period of April through March, as determined by the AURORA model.

Q. How does the March Forecast differ from the October Update?

A. The October Update was calculated by simulating 88 water year conditions in the AURORA model and then averaging the results of all 88 resulting NPSE scenarios to create an "average" or "normal" expectation of NPSE. In contrast, the March Forecast is calculated by simulating the "expected" water condition during the upcoming APCU test period based on current reservoir levels and the most recent water supply forecast from the Northwest River Forecast Center ("NWRFC"). The results for the October Update are used to update base rates, while the results for the March Forecast are used to update Schedule 55, Annual Power Cost Update.

AURORA Model Inputs

Q. Please describe the variables that are to be updated in the AURORA model for the March Forecast, as described in Order No. 08-238.

A. The following variables, as described in Order No. 08-238, are to be updated in the March Forecast:

a. Fuel prices and transportation costs;

b. Wheeling expenses;

c. Planned outages and forced outage rates;

d. Heat rates;

e. Forecast of normalized sales and loads, updated only for known significant changes since the October APCU filing;

f. Forecast hydro generation from current reservoir levels and the most recent water supply forecast from the NWRFC;

g. Contracts for wholesale power and power purchases and sales;

h. Forward price curve as defined below;

i. Public Utility Regulatory Policies Act of 1978 ("PURPA") contract expenses; and

j. The Oregon state allocation factor.

Q. How do the modeling variables, as described in Order No. 08-238, compare between the 2017 March Forecast and those used to develop the 2017 October Update?

A. All of the modeling variables described in Order No. 08-238 were reviewed for accuracy, and updated where appropriate, in the preparation of the proposed March Forecast. For the April 2017 through March 2018 test period, the following variables changed since the October APCU was prepared: (1) fuel prices, (2) planned outage schedule, (3) heat rates, (4) forecast of hydro generation from stream flow conditions using the most recent water supply forecast from the NWRFC and current reservoir levels, (5) known power purchases and surplus sales made in compliance with the Company's Energy Risk Management Policy, (6) forward price curve, and (7) PURPA contract expenses.

Fuel Expense

Q. How frequently are the Company's fuel cost forecasts updated?

A. The coal and gas price forecasts are refreshed monthly for operational planning purposes. When the October Update was prepared, information from the September 2016 Operations Plan was used. The March Forecast determination of NPSE includes the Company's most current coal and gas price forecasts.

Q. How did the AURORA modeled dispatch cost of coal generation change compared to the October Update results?

A. The modeled dispatch per-unit cost for each of the Company's coal-fired thermal generation plants has been updated to reflect current operating costs. The modeled dispatch per-unit cost at the Jim Bridger power plant ("Bridger") increased from

$32.53 per megawatt-hour ("MWh") to $34.98 per MWh. The per-unit cost of output at the Boardman plant ("Boardman") decreased, moving from $28.06 per MWh to $26.58 per MWh. The per-unit cost of output at the North Valmy plant ("Valmy") decreased from $49.91 per MWh to $42.49 per MWh.

Q. What factors drove the changes in the AURORA modeled dispatch cost of generation at the Company's coal plants since the October Update was filed?

A. The per-unit variable cost of production at the Company's Boardman and Valmy plants decreased between the October Update and the March Forecast primarily due to lower coal costs. The cost of coal, on a dollar per MMBtu basis, decreased at Boardman and Valmy due to an increase in the thermal content of the coal, or Btu per pound of coal. The increase in the thermal content yields an increase in the amount of generation produced per pound of coal, which ultimately leads to less coal consumption per MWh and a subsequent reduction in coal costs.

The increase in the per-unit cost of production at Bridger is driven by an increase in coal costs and lower production volumes. Due to low market prices and low-cost natural gas, Bridger generation is being displaced and the ability to economically dispatch the plant for surplus sales is reduced. As a result of reduced generation at Bridger, the Bridger Coal Company ("BCC") mine plan was adjusted in late 2016 to reflect reduced coal volumes. Lower production at the mine is resulting in fixed costs being recovered over fewer tons, causing the cost per ton of coal to increase.

Q. Did the Company model Oil, Handling, and Administrative and General ("OHAG") expenses in the same manner as the October Update?

A. Yes. Per the terms of the settlement stipulation approved in the 2016 APCU, for the March Forecast the Company included within the AURORA model the per-MWh OHAG expense driven by Idaho Power's dispatch of each coal plant. The Company separately accounted for its proportional share of the total OAHG expenses incurred at each of the coal plants.

Q. Did the Company update its forecast of total OHAG expenses as recommended by Staff in opening testimony?

A. Yes. In opening testimony, Staff recommended a change to the Company's OHAG forecast methodology. Staff recommended the forecast be based on a three-year historical average of actual OHAG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate. Staff also recommended the update to the forecast be included in the 2017 March Forecast.

In my March 3, 2017, reply testimony, the Company agreed to Staff's proposal to update the OHAG forecast for the 2017 March Forecast. The forecast of total OHAG expenses for the Bridger, Boardman, and Valmy plants are displayed on lines 6, 12, and 18 of Exhibit 302, respectively.

Q. How did the gas price forecast included in the March Forecast change as compared to the gas price forecast included in the October Update?

A. The gas price forecast used for the October Update for Henry Hub was $3.05 per MMBtu, while the gas price forecast used for the March Forecast for Henry Hub was $3.19 per MMBtu, an increase of $0.14 per MMBtu. The increase in the Henry Hub price from the October Update to the March Forecast is driven by higher demand, including increased capacity for gas-fired electric generation, growing domestic consumption, and increased U.S. exports of natural gas, all of which are leading to lower inventory levels. For the October Update, anticipated gas storage levels were approximately 8 percent above year-ago storage levels and 11 percent above the five-year average for that time period.[2] Gas storage levels for the March Forecast

[2] "Natural Gas Weekly Update." *Natural Gas.* U.S. Energy Information Administration, 8 Sept. 2016. Web. 14 Mar. 2017.

are approximately 10 percent below year-ago levels and 7 percent above the five-year average.[3]

Q. How is the Henry Hub gas price forecast used as an AURORA input?

A. The Company uses the gas price forecast for Henry Hub as the starting point in the AURORA model. Henry Hub is considered a reference fuel in AURORA, meaning other gas market prices are determined by applying an adjustment factor to the Henry Hub price. For example, a Henry Hub gas price of $3.19 per MMBtu applied to a Sumas basis of a negative $0.37 per MMBtu equals a Sumas gas price of $2.82 per MMBtu ($3.19 + ($0.37) = $2.82). The Company develops a separate gas price for its natural gas units also based upon the Henry Hub gas price forecast.

PURPA Expense

Q. Please describe any changes to PURPA generation since the October Update.

A. The October Update included 352 average megawatts ("aMW") of available PURPA generation, whereas the PURPA generation included in the March Forecast is 334 aMW, a decrease of 18 aMW since the October Update.

Q. What is driving the changes in PURPA generation since the October Update?

A. The decrease in PURPA generation is primarily due to the expiration of an Energy Sales Agreement ("ESA") between Idaho Power and Magic Valley, a 10 megawatt co-generation project. The Magic Valley ESA expired in November 2016, and the project did not request a replacement ESA. The decrease in PURPA generation is also driven by a reduction in forecast generation of three wind projects (Durbin Creek Windfarm, Jett Creek Windfarm, and Prospector Windfarm), the ID Solar 1 solar

[3] "Weekly Natural Gas Storage Report." U.S. Energy Information Administration. 9 Mar. 2017. Web. 14 Mar. 2017.

project, and the Simplot-Pocatello co-generation project, which collectively reflect a decrease of 6.4 aMW.

Q. How does total PURPA expense included in the March Forecast compare to the level of PURPA expense included in the October Update?

A. Total PURPA expense included in the March Forecast is $208.8 million compared to the $218.1 million included in the October Update, a decrease of $9.3 million. The largest driver for the decrease in PURPA expense is the expiration of the Magic Valley ESA, which included a forecast contract value of $4.1 million in the October Update. The other projects mentioned above reflect a collective reduction of $3.1 million in PURPA expense between the October Update and March Forecast.

Normalized Load

Q. Please explain the change between the forecast of normalized load used in the October Update and the March Forecast.

A. There was no change in the forecast of normalized load between the October Update and the March Forecast. The forecast of normalized load used for the October Update and March Forecast was 1,817 aMW.

Hydro Forecast

Q. What was the date of the water supply forecast from the NWRFC that was used to create the hydro generation forecast for the March Forecast?

A. The forecast of monthly hydro generation levels included in the March Forecast reflects the NWRFC's March 3, 2017, forecast. The March 3, 2017, forecast has expected inflows into Brownlee Reservoir for April through July of 7.58 million acre-feet ("MAF"), or 2.11 MAF above the 30-year (1981-2010) average volume of 5.47 MAF.

Q. How does this year's water supply forecast compare to last year's NWRFC forecast?

A. The NWRFC's forecast used in last year's March Forecast was 4.62 MAF compared to this year's forecast of 7.58 MAF, which is 64 percent higher than last year, and 39 percent higher than the 30-year average.

Q. How does the increase in expected inflows impact this year's hydro generation forecast compared to last year's forecast?

A. The hydro generation forecasted for this year's March Forecast is 8.7 million MWh compared to 7.8 million MWh in last year's March Forecast, a 12 percent increase.

Q. Please explain why the higher NWRFC forecast of inflows at Brownlee does not translate into a proportional increase in hydro generation compared to last year.

A. Although forecast inflows into Brownlee Reservoir are 64 percent higher for the months of April through July, Brownlee headwater elevation in the months of February, March, and April will be lower than normal due to flood control operations. The U.S. Army Corp of Engineers manages a region-wide flood control plan for the entire Columbia River Basin, and it sets water surface elevation targets for Brownlee Reservoir. In above average water years, such as this year, lower headwater elevation targets are set for Brownlee Reservoir in the spring, as the Company has to make room to capture anticipated runoff to prevent downstream flooding. For April 30, 2017, the forecasted elevation target for Brownlee Reservoir is 2,027 feet. Last year the April 30, 2017, forecasted target was an elevation of 2,042 feet, a decrease of 15 feet.

Additionally, although the inflows into Brownlee Reservoir are higher than last year, flow through the generators is limited by the capacity of each unit. The Brownlee hydro facility can run approximately 35,000 cubic feet per second ("cfs"). Any flows in excess of this capacity is spilled past the dam and cannot be used for generation. For the month of April 2017, inflows at Brownlee are forecast at 43,959 cfs, which is 72 percent higher than last April. However, because the inflows are in excess of Brownlee's capacity, the water has to be spilled rather than used for generation.

While the forecast generation for the months of April through July are up from last year by 49 percent, 37 percent, 28 percent, and 17 percent, respectively, for the remaining months of the test period, the forecast hydro generation levels out and more closely aligns with a normal water year.

Q. How does the hydro generation forecast compare to the normalized scenario used for the October Update?

A. The hydro generation forecasted under the normalized scenario (88 water years) for the October Update was 8.65 million MWh, while the hydro generation forecasted under this year's March Forecast is 8.72 million MWh, an increase of 0.07 million MWh or 8 aMW (0.07 million MWh ÷ 8,760 hours = 8 aMW).

Known Power Purchases and Surplus Sales

Q. Did the Company include known power purchases and surplus sales resulting from the Company's Energy Risk Management Policy in the March Forecast?

A. Yes. The Company includes known power purchases and surplus sales resulting from the Company's Energy Risk Management Policy and incorporates those amounts as Net Hedges on Exhibit 302, lines 41 and 42, as directed by Order No. 08-238. Known power purchases and surplus sales are not included in the October Update of the APCU.

Other

Q. What other AURORA inputs have changed since the October Update?

A. The Company updated the planned outage schedule and heat rates for its thermal plants. Forced outage rates remain unchanged from the October Update.

2017 Forecast NPSE

Q. Have you prepared an exhibit that summarizes the total NPSE for the March Forecast?

A. Yes. Exhibit 302 shows the results of the AURORA modeling determination of forecast NPSE, as well as the re-pricing of market purchases and surplus sales, and total PURPA expense for the April 2017 through March 2018 test year.

Re-Pricing Based on a Forward Price Curve

Q. What forward price curve did the Company use to re-price purchased power and surplus sales?

A. Exhibit 301 shows the March 8, 2017, Mid-C Heavy Load (HL) and Light Load (LL) forward price curve for the April 2017 through March 2018 test period the Company used for the March Forecast, as directed by Order No. 08-238.

Q. What is the Company's March Forecast of NPSE as a result of the changes described above?

A. Exhibit 302 shows the results of a single water condition for the April 2017 through March 2018 test period, with updated fuel prices, normalized load, updated stream flow conditions, updated power purchases and surplus sales from the Company's Energy Risk Management Policy (Net Hedges), market purchased power and surplus sales re-priced, and updated PURPA contract expenses. The March Forecast for NPSE without PURPA expenses is $177.0 million. When PURPA expenses of $208.8 million are included, the total NPSE for the March Forecast is $385.8 million.

Q. How does the modeled generation in the 2017 March Forecast compare to last year's March Forecast?

A. A high level analysis of the results suggests that increased hydro generation and low-cost market purchases have replaced natural gas generation and the reduction in forecast PURPA generation, as well as allowed for higher surplus sales volumes when compared to last year's March Forecast levels. Coal generation was relatively unchanged from last year.

Q. Can you elaborate more on the changes in generation from the 2016 March Forecast to the 2017 March Forecast?

A. Yes. The hydro generation forecast for the 2017 March Forecast was 0.9 million MWh more than last year, resulting from higher forecast inflows at Brownlee reservoir for April through July. The increase in hydro generation allowed for increased surplus sales, particularly in April and May 2017, as can be seen on line 37 of Exhibit 302. In total, surplus sales volumes were 0.6 million MWh higher than last year's March Forecast.

Although the forecast gas price remains below the 5-year average Henry Hub price of $3.49 per MMBtu,[4] the price increased from $2.68 per MMBtu for last year's March Forecast to $3.19 per MMBtu for this year's March Forecast. The increase in natural gas prices decreased production at the Company's natural gas-fired plants by 0.3 million MWh compared to last year's March Forecast. The cost of production from last year's March Forecast for all natural gas-fired generation was $21.42 per MWh, while this year's March Forecast expects an average price of $24.84 per MWh, an increase of $3.42 per MWh.

Market purchase volumes increased from 0.6 million MWh to 0.9 million MWh, an increase of 0.3 million MWh from last year's March Forecast. The average

[4] "Natural Gas Spot and Futures Prices." *Natural Gas.* U.S. Energy Information Administration, 15 Mar. 2017. Web. 16 Mar. 2017.

re-priced market purchase price from last year's March Forecast was $20.23 per MWh, while this year's March Forecast expects an average market purchase price of $24.10 per MWh, an increase of $3.87 per MWh, resulting in an $8.7 million increase to NPSE. Although the average re-priced market purchase price increased from last year's March Forecast, the price remains below the average production cost of $24.84 per MWh for all the Company's natural gas-fired generation plants and $35.27 per MWh for the coal-fired generation plants.

Q. If hydro generation and low-cost market purchases are displacing natural gas generation and surplus sales volumes increased, why is NPSE increasing as compared to last year's March Forecast?

A. The re-pricing of market purchases and sales is the primary reason for the increase in NPSE year-over-year. For this year's March Forecast, re-pricing of market purchases and sales results in a net increase in NPSE of $14.5 million; the re-pricing of purchased power results in a $4.4 million decrease in NPSE, while causing a decrease in surplus sales revenues of $18.9 million. Although surplus sales volumes were 0.6 million MWh higher than last year's March Forecast, re-pricing based on the March 8, 2017, forward price curve reduced the value of surplus sales from $22.65 per MWh (as modeled in AURORA) to $11.78 per MWh.

Per-Unit Cost Calculation and Quantification of the Revenue Requirement Impact

Q. What is the March Forecast unit cost per MWh for this filing?

A. Exhibit 302 shows the normalized annual sales at the customer level for the April 2017 through March 2018 test period of 14,661,439 MWh (line 46). Based upon test period sales, the cost per-unit for the March Forecast is $26.31 per MWh ($385.8 million / 14.661 million MWh = $26.31 per MWh) (lines 45, 46, and 48).

Q. Please describe the calculation necessary to determine the March Forecast rate.

A. Exhibit 303 steps through the Commission-specified method of calculating the March Forecast rate, pursuant to Order No. 08-238. Lines 1-3 show the calculation for the October Update unit cost of $26.06 per MWh. Lines 4-6 show the calculation for the March Forecast unit cost of $26.31 per MWh. Line 7 reflects the March Forecast unit cost minus the October Update unit cost multiplied by the March Forecast Normalized Sales (line 6 minus line 3 multiplied by line 4). Line 8 is the allocated amount (95 percent) that is allowed for the March Forecast rate. Line 9, the Forecast Change Allowed, is calculated by multiplying line 7 by line 8. Line 10 is calculated by dividing line 9 by line 4 to calculate the March Forecast rate of $0.24 per MWh.

Q. How does this $0.24 per MWh compare to the March Forecast rate that resulted from last year's computation?

A. The March Forecast rate for last year's April 2016 through March 2017 test period was $1.34 per MWh, as compared to this year's April 2017 through March 2018 test period rate of $0.24 per MWh, a decrease of $1.10 per MWh.

Q If NPSE is increasing as compared to last year's March Forecast, why is the March Forecast rate a decrease from last year?

A. As described above, the March Forecast rate is based on 95 percent of the change in NPSE between the October Update and the March Forecast, as shown on line 7 of Exhibit 303. For this year's March Forecast, the allowed difference in the normal expectation of NPSE as determined by the October Update and the expected NPSE based on the March Forecast is $3.5 million. For last year's March Forecast, the allowed difference in the normal expectation of NPSE as determined by the October Update and the expected NPSE based on the March Forecast was $19.6 million. Although total forecast NPSE for this year's March Forecast is an increase over last year, the allowed difference in NPSE between the October Update and March Forecast is less, resulting in a lower March Forecast rate. In other words, this year's

March Forecast of expected NPSE more closely aligns with a normal expectation of NPSE as determined in the October Update.

Q. How is the revenue requirement for the March Forecast calculated using the March Forecast rate unit cost of $0.24 per MWh?

A. The revenue requirement for the March Forecast is calculated by multiplying the March Forecast rate of $0.24 per MWh by the loss adjusted Oregon jurisdictional sales for the April 2017 through March 2018 test period of 683,817.790 MWh, creating a revenue requirement of approximately $0.2 million, as shown on page 2 of Exhibit 304, lines 47, 48, and 49. Revenues collected through the current March Forecast rate of $1.34 per MWh, are approximately $0.9 million. As such, the proposed 2017 March Forecast rate of $0.24 per MWh will result in a revenue requirement decrease of $0.7 million compared to what is currently included in Oregon customers' rates.

Rate Implementation

Q. What method of allocation are you proposing to spread the incremental revenue requirement associated with the March Forecast to the various customer classes?

A. The Company proposes to allocate the revenue deficiency associated with the 2017 March Forecast according to the revenue spread methodology approved by the Commission in Order No. 10-191, Docket No. UE 214.[5] Order No. 10-191 established a revenue-spread methodology whereby the revenue deficiency for the March Forecast is allocated to individual customer classes on the basis of the total generation-related revenue requirement approved in the Company's last general rate

[5] *Re Idaho Power Company's 2010 Annual Power Cost Update*, Docket No. UE 214, Order No. 10-191 (May 24, 2010).

case. In this instance, the Company's last general rate case, Docket No. UE 233, was a settled case in which the parties did not adopt the Company's class cost-of-service methodology, but rather agreed to a revenue spread methodology that was set forth in Exhibit B to the Partial Stipulation filed on February 1, 2012.[6] In light of the stipulated revenue spread, the Company has utilized the total generation-related revenue requirement detailed on Exhibit B to the Partial Stipulation to apportion the March Forecast revenue requirement to each customer class. The proposed revenue spread resulting from the application of the stipulated methodology in Docket No. UE 233 is shown on Exhibit 304.

Q. Did the Company revise the revenue spread for the October Update?

A. Yes. The Company revised the revenue spread for the October Update to align with the loss adjusted sales that were used for the March Forecast filing. The practice of updating the loss adjusted sales for the October Update revenue spread is consistent with the method applied in the last five APCU filings in Docket Nos. UE 242, UE 257, UE 279, UE 293, and UE 301. The loss adjusted sales for the October Update were 686,534.333 MWh, whereas the loss adjusted sales for the March Forecast are 683,817.790, a decrease of 2,716.54 MWh.

Q. Based on testimony and discussions with parties in this proceeding, is the Company proposing any other adjustments to the October Update filing?

A. Yes. In opening testimony, Staff recommended a change in the methodology used to allocate power costs.[7] The Commission-approved APCU methodology allocates power costs to the Oregon jurisdiction by multiplying the system incremental per-unit cost by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the

[6] *In the Matter of Idaho Power Co. Request for General Rate Revision*, Docket No. UE 233, Order No. 12-055, Appendix A at 16 (Feb. 23, 2012).

[7] Staff/200, Kaufman/2 lines 8-9.

test period. However, Staff recommended that the Company calculate the Oregon jurisdictional revenue requirement using the system total per-unit cost for the test period, not the incremental per-unit cost.

After reviewing Staff's recommendation, the Company agreed to move forward with the proposed total per-unit cost method in place of the existing incremental approach. As such, the Company adjusted the rate calculation for the October Update. Rather than using the system incremental per-unit cost of $2.13 per MWh, the Company used the system total per-unit cost of $26.06 per MWh to determine the Oregon jurisdictional revenue requirement. Using the system total per-unit cost, as well as adjusting the loss adjusted sales to align with the March Forecast as discussed previously, results in a decrease in the Oregon jurisdictional revenue requirement of $115,731 relative to the October Update contained in the Company's initial filing, as shown on line 53 of Exhibit 304.

Q. What is the overall revenue impact of this year's combined October Update and March Forecast compared to last year's combined October Update and March Forecast using the rate spread methodology described above?

A. Exhibit 305 provides a summary of the revenue change resulting from this year's combined October Update and March Forecast as compared to current revenue. As can be seen on line 11 of Exhibit 305, the overall revenue impact of this year's combined October Update and March Forecast is an increase of approximately $0.6 million or 1.08 percent overall. The $0.6 million increase reflects an increase of $1.3 million in base rate revenues associated with the October Update, and a $0.7 million decrease in Schedule 55 revenues associated with the March Forecast, as compared to what is currently included in Oregon customers' rates related to the 2016 APCU.

Q. In your reply testimony, you indicated that the Company was working with the parties to establish a process for providing workpapers to the parties. Were you able to reach an agreement?

A. Yes. At the March 6, 2017, workshop, the Company, Staff, and CUB reached an agreement on the types of workpapers that would be provided with the 2017 March Forecast and the timeframe for providing them. As part of this filing, the Company will provide its workpapers to Staff and CUB consistent with that agreement.

Q. Will the Company continue to work with the parties to memorialize the agreement?

A. Yes. The Company will continue to work with the parties to determine if workpapers provided with the 2017 March Forecast, as well as the timeline and process for providing the workpapers, are agreeable. The Company intends to memorialize the final agreement reached with parties in order to establish a prescribed process for submitting workpapers in future APCU filings.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 314
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

March 8, 2017, Mid-Columbia Price Curve for April 2017 – March 2018

March 24, 2017

IDAHO POWER COMPANY
Mid-Columbia Heavy Load and Light Load Daily Forward Curves
Used to Re-Price Purchased Power (PP) and Surplus Sales (SS) for the March Forecast

Line	Mid-Columbia Forward Price Curve on:												
1	**3/8/2017**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**
2	**mc HL**	11.70	11.55	12.50	24.20	29.25	26.60	23.60	25.55	31.20	31.20	27.70	22.15
3	**mc LL**	4.70	3.90	4.10	11.55	20.75	22.00	20.45	21.75	25.85	25.25	22.90	18.50
4	**Reallocated Prices**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**
5	**HL PP**												
6	103.9%	12.16	12.00	12.99	25.14	30.39	27.64	24.52	26.55	32.42	32.42	28.78	23.01
7	**LL PP**												
8	107.1%	5.03	4.18	4.39	12.37	22.22	23.56	21.90	23.29	27.69	27.04	24.53	19.81
9	**HL SS**												
10	96.4%	11.28	11.13	12.05	23.33	28.20	25.64	22.75	24.63	30.08	30.08	26.70	21.35
11	**LL SS**												
12	93.4%	4.39	3.64	3.83	10.79	19.38	20.55	19.10	20.31	24.14	23.58	21.39	17.28

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 314
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Power Supply Costs for April 1, 2017 – March 31, 2018

March 24, 2017

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2017 -- MARCH 31, 2018 (One Hydro Condition)
Repriced Using UE 195 Settlement Methodology - March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	1,173,209.5	1,265,470.9	1,015,180.5	711,391.7	476,345.4	391,246.2	492,833.4	396,160.0	482,662.8	706,310.4	737,297.6	872,717.8	8,720,826.3
	Bridger													
2	Energy (MWh)	-	-	3,196.6	205,813.6	286,658.8	165,864.4	99,776.5	133,508.0	228,168.1	70,200.8	29,945.5	3,399.7	1,226,532.0
3	AURORA Modeled Expense ($ x 1000)	-	-	113.0	6,703.9	9,295.2	5,406.9	3,294.5	4,427.3	7,487.2	2,388.5	1,018.0	119.8	40,254.2
4	AURORA Modeled Handling Expense ($ x 1000)	-	-	0.4	24.7	34.4	19.9	12.0	16.0	27.4	8.4	3.6	0.4	147.2
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 112.6	$ 6,679.2	$ 9,260.8	$ 5,387.0	$ 3,282.6	$ 4,411.2	$ 7,459.9	$ 2,380.0	$ 1,014.4	$ 119.4	$ 40,107.0
6	IPC Share of OHAG Expense ($ x 1000)	$ 233.3	$ 233.3	$ 233.3	$ 233.3	$ 233.3	$ 233.3	$ 233.3	$ 233.3	$ 233.3	$ 233.3	$ 233.3	$ 233.3	$ 2,799.1
7	Total Expense ($ x 1000)	$ 233.3	$ 233.3	$ 345.9	$ 6,912.4	$ 9,494.1	$ 5,620.2	$ 3,515.8	$ 4,644.5	$ 7,693.1	$ 2,613.3	$ 1,247.6	$ 352.6	$ 42,906.1
	Boardman													
8	Energy (MWh)	5,261.0	9,199.0	18,548.8	35,102.9	40,800.7	34,946.9	32,010.3	34,957.5	37,137.6	20,536.0	17,857.1	10,432.0	296,789.8
9	AURORA Modeled Expense ($ x 1000)	145.7	251.0	480.3	879.2	1,017.2	874.3	806.1	872.8	924.3	601.4	526.6	327.1	7,706.0
10	AURORA Modeled Handling Expense ($ x 1000)	0.3	0.5	0.9	1.8	2.0	1.7	1.6	1.7	1.9	1.0	0.9	0.5	14.8
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 145.5	$ 250.6	$ 479.4	$ 877.5	$ 1,015.1	$ 872.5	$ 804.5	$ 871.1	$ 922.4	$ 600.3	$ 525.7	$ 326.6	$ 7,691.2
12	IPC Share of OHAG Expense ($ x 1000)	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 196.5
13	Total Expense ($ x 1000)	$ 161.8	$ 266.9	$ 495.7	$ 893.9	$ 1,031.5	$ 888.9	$ 820.9	$ 887.5	$ 938.8	$ 616.7	$ 542.1	$ 343.0	$ 7,887.7
	Valmy													
14	Energy (MWh)	-	-	3,606.8	58,596.2	78,964.3	45,911.9	42,004.2	34,715.9	59,960.4	33,138.9	31,371.0	18,959.6	407,229.3
15	AURORA Modeled Expense ($ x 1000)	-	-	131.0	1,877.8	2,517.8	1,485.8	1,379.9	1,138.0	1,922.4	1,095.8	1,065.4	664.7	13,278.7
16	AURORA Modeled Handling Expense ($ x 1000)	-	-	3.3	53.9	72.6	42.2	38.6	31.9	55.2	30.5	28.9	17.4	374.7
17	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 127.7	$ 1,823.9	$ 2,445.2	$ 1,443.6	$ 1,341.2	$ 1,106.0	$ 1,867.2	$ 1,065.3	$ 1,036.6	$ 647.3	$ 12,904.0
18	IPC Share of OHAG Expense ($ x 1000)	$ 366.6	$ 366.6	$ 366.6	$ 366.6	$ 366.6	$ 366.6	$ 366.6	$ 366.6	$ 366.6	$ 366.6	$ 366.6	$ 366.6	$ 4,398.6
19	Total Expense ($ x 1000)	$ 366.6	$ 366.6	$ 494.2	$ 2,190.4	$ 2,811.7	$ 1,810.2	$ 1,707.8	$ 1,472.6	$ 2,233.8	$ 1,431.9	$ 1,403.1	$ 1,013.9	$ 17,302.7
	Langley Gulch													
20	Energy (MWh)	171,066.3	189,490.2	188,023.7	198,905.8	199,049.8	194,655.5	197,280.1	192,022.8	211,958.4	196,588.6	173,575.6	179,249.2	2,291,866.0
21	Expense ($ x 1000)	$ 2,792.1	$ 3,019.4	$ 3,161.9	$ 3,696.8	$ 3,845.9	$ 3,730.9	$ 3,830.4	$ 4,172.4	$ 5,211.5	$ 4,644.7	$ 3,948.8	$ 3,991.9	$ 46,046.6
	Danskin													
22	Energy (MWh)	667.6	1,159.8	19,957.7	47,583.1	54,726.9	39,960.6	15,707.7	5,411.7	2,915.4	1,457.4	2,118.3	87.2	191,753.3
23	Expense ($ x 1000)	$ 18.0	$ 30.6	$ 555.3	$ 1,483.8	$ 1,775.4	$ 1,263.2	$ 500.8	$ 191.4	$ 116.0	$ 55.8	$ 78.4	$ 3.2	$ 6,071.8
	Bennett Mountain													
24	Energy (MWh)	159.6	125.4	8,218.1	31,994.7	34,367.4	24,569.9	7,464.9	1,836.4	1,393.1	152.5	736.1	-	111,018.1
25	Expense ($ x 1000)	$ 4.4	$ 3.4	$ 232.5	$ 996.0	$ 1,109.8	$ 785.8	$ 241.5	$ 65.9	$ 56.2	$ 5.9	$ 27.6	$ -	$ 3,529.0
26	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 725.0	$ 748.7	$ 746.0	$ 770.4	$ 770.4	$ 746.0	$ 748.7	$ 725.0	$ 748.7	$ 717.9	$ 649.6	$ 717.9	$ 8,814.0
	Purchased Power (Excluding PURPA)													
27	Market Energy (MWh)	-	-	60,702.6	98,743.0	158,802.8	104,848.6	44,483.8	114,539.2	97,109.7	144,450.5	35,075.5	5,065.0	863,820.7
28	Elkhorn Wind Energy (MWh)	25,222.8	24,240.8	24,790.8	26,601.0	23,943.0	21,200.4	22,027.8	30,132.4	29,442.4	26,367.6	23,457.6	29,036.4	306,462.7
29	Neal Hot Springs Energy (MWh)	14,081.9	11,353.2	10,318.6	8,357.0	9,713.8	11,676.6	13,859.1	17,054.5	17,838.6	18,323.1	16,285.0	16,438.1	165,299.4
30	Raft River Geothermal Energy (MWh)	6,088.1	5,065.7	5,127.2	5,756.7	5,203.9	5,842.0	7,652.8	6,785.9	7,035.5	7,084.5	6,387.4	6,429.4	74,459.1
31	Total Energy Excl. PURPA (MWh)	45,392.8	40,659.6	100,939.2	139,457.7	197,663.5	143,567.5	88,023.5	168,512.0	151,426.2	196,225.6	81,205.5	56,968.9	1,410,042.0
32	Market Expense ($ x 1000)	$ -	$ -	$ 485.0	$ 1,706.7	$ 3,998.6	$ 2,702.6	$ 1,044.7	$ 2,865.8	$ 2,846.4	$ 4,181.1	$ 882.8	$ 100.8	$ 20,814.5
33	Elkhorn Wind Expense ($ x 1000)	$ 1,123.7	$ 1,079.9	$ 1,502.6	$ 1,934.7	$ 1,741.4	$ 1,285.0	$ 1,335.1	$ 2,191.5	$ 2,141.3	$ 1,646.1	$ 1,464.5	$ 1,332.5	$ 18,778.2
34	Neal Hot Springs Expense ($ x 1000)	$ 1,154.3	$ 930.6	$ 1,153.9	$ 1,121.5	$ 1,303.6	$ 1,305.8	$ 1,549.9	$ 2,288.7	$ 2,393.9	$ 2,097.8	$ 1,864.5	$ 1,379.5	$ 18,544.0
35	Raft River Geothermal Expense ($ x 1000)	$ 289.2	$ 240.6	$ 331.4	$ 446.5	$ 403.6	$ 377.6	$ 494.6	$ 526.3	$ 545.7	$ 467.5	$ 421.5	$ 311.8	$ 4,856.3
36	Total Expense Excl. PURPA ($ x 1000)	$ 2,567.2	$ 2,251.2	$ 3,472.8	$ 5,209.4	$ 7,447.1	$ 5,670.9	$ 4,424.3	$ 7,872.4	$ 7,927.4	$ 8,392.5	$ 4,633.2	$ 3,124.6	$ 62,993.0
	Surplus Sales													
37	Energy (MWh)	570,267.1	549,441.4	103,245.5	51,616.0	19,358.6	17,122.4	66,046.3	11,051.4	22,804.7	18,262.7	97,498.1	216,162.9	1,742,877.1
38	Revenue Including Transmission Expenses ($ x 1000)	$ 5,055.1	$ 4,477.7	$ 1,063.9	$ 1,064.8	$ 524.8	$ 404.2	$ 1,393.3	$ 260.2	$ 656.1	$ 525.8	$ 2,454.2	$ 4,398.3	$ 22,278.5
39	Transmission Expenses ($ x 1000)	$ 570.3	$ 549.4	$ 103.2	$ 51.6	$ 19.4	$ 17.1	$ 66.0	$ 11.1	$ 22.8	$ 18.3	$ 97.5	$ 216.2	$ 1,742.9
40	Revenue Excluding Transmission Expenses ($ x 1000)	$ 4,484.8	$ 3,928.3	$ 960.7	$ 1,013.2	$ 505.5	$ 387.1	$ 1,327.2	$ 249.2	$ 633.3	$ 507.5	$ 2,356.7	$ 4,182.2	$ 20,535.6
	Net Hedges													
41	Energy (MWh)	-	-	-	55,800.0	21,600.0	-	-	-	-	-	-	-	77,400.0
42	Cost($ X 1000)	$ -	$ -	$ -	$ 1,198.2	$ 750.6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,948.8
43	Net Power Supply Expenses ($ x 1000)	$ 2,383.4	$ 2,991.6	$ 8,543.6	$ 22,338.2	$ 28,531.1	$ 20,128.9	$ 14,462.9	$ 19,782.5	$ 24,292.2	$ 17,971.2	$ 10,173.8	$ 5,364.8	$ 176,964.1
44	PURPA ($ x 1000)	$23,913.74	$21,825.41	$17,779.17	$15,161.02	$16,056.99	$15,908.64	$12,584.63	$14,440.47	$13,580.51	$16,939.55	$19,327.11	$21,288.30	$ 208,805.5
45	Total Net Power Supply Expenses ($ x 1000)	$ 26,297.2	$ 24,817.0	$ 26,322.8	$ 37,499.2	$ 44,588.0	$ 36,037.6	$ 27,047.5	$ 34,222.9	$ 37,872.7	$ 34,910.7	$ 29,500.9	$ 26,653.1	**$ 385,769.6**
46	Sales at Customer Level (In 000s MWH)	1,028.649	1,073.076	1,239.869	1,483.492	1,550.545	1,407.258	1,112.181	1,036.226	1,151.526	1,268.249	1,212.377	1,097.992	14,661.439
47	Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
48	Unit Cost / MWH (for PCAM)	$25.56	$23.13	$21.23	$25.28	$28.76	$25.61	$24.32	$33.03	$32.89	$27.53	$24.33	$24.27	**$26.31**
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
49	Portion of Purchased Power considered HL Purchases	**0.00%**	0.00%	41.86%	38.47%	36.19%	54.33%	60.47%	53.08%	34.37%	35.39%	15.10%	2.77%	
50	Purchased Power HL Price	12.16	12.00	12.99	25.14	30.39	27.64	24.52	26.55	32.42	32.42	28.78	23.01	
51	Portion of Surplus Sales considered HL Surplus Sales	**64.95%**	60.16%	78.77%	78.48%	87.67%	60.04%	54.66%	74.90%	78.00%	80.17%	71.18%	75.32%	
52	Surplus Sales HL Price	11.28	11.13	12.05	23.33	28.20	25.64	22.75	24.63	30.08	30.08	26.70	21.35	
	Light Load													
53	Portion of Purchased Power considered LL Purchases	**0.00%**	0.00%	58.14%	61.53%	63.81%	45.67%	39.53%	46.92%	65.63%	64.61%	84.90%	97.23%	
54	Purchased Power LL Price	5.03	4.18	4.39	12.37	22.22	23.56	21.90	23.29	27.69	27.04	24.53	19.81	
55	Portion of Surplus Sales considered LL Surplus Sales	**35.05%**	39.84%	21.23%	21.52%	12.33%	39.96%	45.34%	25.10%	22.00%	19.83%	28.82%	24.68%	
56	Surplus Sales LL Price	4.39	3.64	3.83	10.79	19.38	20.55	19.10	20.31	24.14	23.58	21.39	17.28	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 314
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

October Update and March Forecast
Combined Rate Calculation for April 2017 – March 2018

March 24, 2017

APCU Combined Rate Calculation
April 2017 - March 2018

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,661,439
2	Total Net Power Supply Expense	$382,067,704
3	October APCU Unit Cost ($/MWh)	$26.06
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,661,439
5	Total Net Power Supply Expense	$385,769,624
6	March Forecast Unit Cost ($/MWh)	$26.31
7	Sales Adjusted Forecast Power Cost Change	$3,665,360
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$3,482,092
10	**March Forecast Rate ($/MWh)**	$0.24
11	**Combined Rate ($/MWh)**	$26.30

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 314
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Revenue Spread for October Update and March Forecast

March 24, 2017

Idaho Power Company
Revenue Spread Exhibit for October Update APCU

General Rate Case (UE 233): Marginal Cost-of-Service Study and Stipulated Revenue Spread

2011 Test Period

Line No.	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
1	**Normalized Sales (kWh)**	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	**Current Revenue**	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	**Demand Related Marginal Cost**													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	**Energy Related Marginal Cost**													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	**Simple-Summed Energy-Related and Demand-Related Marginal Costs**													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	**Customer Related Marginal Cost**	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	**Total Functionalized Revenue Requirement**													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	**Total: Staff-Adjusted Allocation**	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	**Revenue Deficiency - Staff Adj. Allocation**	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	**% Increase Required by Staff Adj. Alloc. Approach**	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	**$ Increase Recommended per Stipulation**	**$1,810,890**	**$862,348**	**$44,153**	**$197,517**	**$22,598**	**$0**	**$0**	**$232,545**	**$212,777**	**$235,318**	**$44**	**$3,507**	**$84**
34	**% Increase Recommended per Stipulation**	**4.54%**	**5.62%**	**2.83%**	**2.83%**	**2.83%**	**0.00%**	**0.00%**	**2.83%**	**6.81%**	**6.81%**	**4.56%**	**2.83%**	**6.81%**
35	**Average Rate Given Stipulation ($/kWh)**	**0.0641**	**0.0816**	**0.0899**	**0.0628**	**0.0544**	**0.0547**	**0.2324**	**0.0471**	**0.0450**	**0.0791**	**0.0788**	**0.1637**	**0.0805**
36	**Final Revenue Allocation**	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	**Spread Floors and Ceilings:**													
39	No increase for those warranting a decrease greater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													

2017 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures

Line No.	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
42	2017 October Update APCU Cost of Service (Allocator -- Line 14)	$17,820,292	$5,860,979	$481,774	$3,065,459	$386,016	$68,933	$9,905	$4,254,042	$2,061,732	$1,614,757	$327	$15,954	$415
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	42.75%	36.14%	30.04%	42.73%	47.04%	44.47%	8.81%	50.37%	61.80%	43.77%	32.22%	12.53%	31.56%
44	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
45	2017 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 44))	27.409	29.475	27.001	26.830	25.566	24.336	20.467	23.741	27.803	34.615	25.381	20.503	25.413
46	**APCU Incremental Rate for 2017 October Update (Mills per kWh) (Line 45*(Column A:[Line 44/Line 47]))**	**26.060**	**31.176**	**25.445**	**25.921**	**23.494**	**26.369**	**22.645**	**25.028**	**19.991**	**24.803**	**60.766**	**17.563**	**18.916**
47	*Loss-Adjusted 2017-2018 Normalized Sales (kWh)*	683,817,790	187,997,680	18,933,795	118,262,874	16,430,586	2,614,124	437,388	169,967,924	103,135,220	65,102,510	5,388	908,365	21,936
48	Projected October Update APCU 2017-2018 Revenues (Line 46 * Line 47)	$17,820,293	$5,860,979	$481,774	$3,065,459	$386,016	$68,933	$9,905	$4,254,042	$2,061,732	$1,614,757	$327	$15,954	$415

Notes:

Line No.			
49	**2017 October Update Base NPSE = $26.06/MWh x 683,817.790 MWhs =**	**$17,820,292**	**(Line 48, Column A)**
50	**NPSE Currently Included in Base Rates =**	**$16,473,704**	
51	**Oregon Jurisdictional Incremental NPSE =**	**$1,346,587**	
52	**Initial October Update Filing Oregon Jurisdictional Incremental NPSE =**	**$1,462,318**	
53		**($115,731)**	

Idaho Power Company
Revenue Spread Exhibit for March Forecast APCU

General Rate Case (UE 233): Marginal Cost-of-Service Study and Stipulated Revenue Spread

2011 Test Period

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
1	**Normalized Sales (kWh)**	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	**Current Revenue**	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	**Demand Related Marginal Cost**													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	**Energy Related Marginal Cost**													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	**Simple-Summed Energy-Related and Demand-Related Marginal Costs**													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	**Customer Related Marginal Cost**	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	**Total Functionalized Revenue Requirement**													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	**Total: Staff-Adjusted Allocation**	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	**Revenue Deficiency - Staff Adj. Allocation**	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	**% Increase Required by Staff Adj. Alloc. Approach**	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	**$ Increase Recommended per Stipulation**	**$1,810,890**	**$862,348**	**$44,153**	**$197,517**	**$22,598**	**$0**	**$0**	**$232,545**	**$212,777**	**$235,318**	**$44**	**$3,507**	**$84**
34	**% Increase Recommended per Stipulation**	**4.54%**	**5.62%**	**2.83%**	**2.83%**	**2.83%**	**0.00%**	**0.00%**	**2.83%**	**6.81%**	**6.81%**	**4.56%**	**2.83%**	**6.81%**
35	**Average Rate Given Stipulation ($/kWh)**	**0.0641**	**0.0816**	**0.0899**	**0.0628**	**0.0544**	**0.0547**	**0.2324**	**0.0471**	**0.0450**	**0.0791**	**0.0788**	**0.1637**	**0.0805**
36	**Final Revenue Allocation**	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														

38 **Spread Floors and Ceilings:**

39 No increase for those warranting a decrease greater than 8%

40 2.83% increase for those warranting a decrease less than 8%

41 No increase greater than one-and-one-half times the average increase

2017 March Forecast APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures

42	2017 March Forecast APCU Cost of Service (Allocator -- Line 14)	$164,116	$53,977	$4,437	$28,231	$3,555	$635	$91	$39,178	$18,988	$14,871	$3	$147	$4
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	0.39%	0.33%	0.28%	0.39%	0.43%	0.41%	0.08%	0.46%	0.57%	0.40%	0.30%	0.12%	0.29%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$41,848,597	$16,272,257	$1,607,990	$7,201,663	$824,255	$155,632	$112,553	$8,484,788	$3,355,157	$3,704,460	$1,019	$127,505	$1,319
45	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
46	2017 March Forecast Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*{Line 42/Line 45})	0.252	0.271	0.249	0.247	0.235	0.224	0.188	0.219	0.256	0.319	0.234	0.189	0.234
47	**APCU Incremental Rate for 2017 March Forecast (Mills per kWh) (Line 46*{Column A:[Line 45/Line 48]})**	**0.240**	**0.287**	**0.234**	**0.239**	**0.216**	**0.243**	**0.209**	**0.231**	**0.184**	**0.228**	**0.560**	**0.162**	**0.174**
48	*Loss-Adjusted 2017-2018 Normalized Sales (kWh)*	683,817,790	187,997,680	18,933,795	118,262,874	16,430,586	2,614,124	437,388	169,967,924	103,135,220	65,102,510	5,388	908,365	21,936
49	Projected March Forecast APCU 2017-2018 Revenues (Line 47 * Line 48)	$164,116	$53,977	$4,437	$28,231	$3,555	$635	$91	$39,178	$18,988	$14,871	$3	$147	$4

Notes:

1 **2017 March Forecast APCU Revenues = $0.24/MWh x 683,817.790 MWhs =** **$ 164,116** **(Line 49, Column A)**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 314
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Summary of Revenue Impact

March 24, 2017

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2017

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	13,655	187,997,680	$18,791,056	99.95	$197,568	$18,988,624	101.00	1.05%
2	Small General Service	7	2,558	18,933,795	$2,007,047	106.00	$15,471	$2,022,518	106.82	0.77%
3	Large General Service	9	913	137,307,584	$10,677,400	77.76	$121,082	$10,798,482	78.64	1.13%
4	Dusk to Dawn Lighting	15	0	437,388	$109,499	250.35	$334	$109,832	251.11	0.30%
5	Large Power Service	19	7	273,103,144	$16,782,708	61.45	$202,514	$16,985,223	62.19	1.21%
6	Agricultural Irrigation Service	24	1,927	65,102,510	$6,384,194	98.06	$55,447	$6,439,640	98.92	0.87%
7	Unmetered General Service	40	2	5,388	$529	98.22	$11	$541	100.33	2.15%
8	Street Lighting	41	25	908,365	$143,870	158.38	$542	$144,412	158.98	0.38%
9	Traffic Control Lighting	42	8	21,936	$2,091	95.32	$13	$2,104	95.90	0.61%
10	Total Uniform Tariffs		19,095	683,817,790	$54,898,394	80.28	$592,982	$55,491,376	81.15	1.08%
11	Total Oregon Retail Sales		19,095	683,817,790	$54,898,394	80.28	$592,982	$55,491,376	81.15	1.08%

(1) Updated April 2017-March 2018 Test Year