McDOWELL RACKNER GIBSON PC
419 SW 11th Ave, Suite 400 | Portland, OR 97205

ALISHA TILL
Direct (503) 290-3628
alisha@mrg-law.com

March 24, 2020

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-1088

Re: UE 366 – Idaho Power Company's 2020 Annual Power Cost Update.

Attention Filing Center:

Attached for filing in the above-referenced docket is a copy of Idaho Power Company's 2020 March Forecast, which includes the Direct Testimony of Nicole A. Blackwell (Idaho Power/300-308).

Please contact this office with any questions.

Sincerely,

/s/ Alisha Till

Alisha Till
Paralegal

Attachments

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 366

IN THE MATTER OF IDAHO POWER COMPANY'S 2020 ANNUAL POWER COST UPDATE	)
MARCH FORECAST	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

NICOLE A. BLACKWELL

March 24, 2020

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

A. Yes. I previously submitted direct testimony in this proceeding regarding the October Update for the 2020 Annual Power Cost Update ("APCU"). The 2020 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 2020 through March 2021.

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

A. The Company filed the 2020 October Update on October 31, 2019, and the Public Utility Commission of Oregon ("Commission") Staff and the Oregon Citizens' Utility Board ("CUB") reviewed the filing. Eleven rounds of discovery requests have been served on the Company since the initial filing. The parties held workshops on January 15, 2020, and January 16, 2020, to discuss the October Update filing. On February 4, 2020, Staff filed opening testimony. The parties held a settlement conference on February 10, 2020. On March 3, 2020, the Company filed reply testimony.

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 previously, the Company filed the first part of the APCU, the October Update, on October 31, 2019. The initial October Update filing proposed a revenue decrease of approximately $176,943, or 0.32 percent. If the March Forecast and October Update are approved as filed, the 2020 composite APCU (both the October Update and March Forecast components) will result in a revenue increase of $556,283 or a 1.01 percent increase, to become effective June 1, 2020.

---

[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).

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

A. The revenue increase requested in this case results from an increase in expected net power supply expense ("NPSE") for the March Forecast, which is partially offset by a decrease in normalized NPSE for the October Update, which has been updated since the initial October Update filing.

The requested revenue requirement for the 2020 March Forecast is approximately $1.57 million, which is a $0.78 million increase compared to the current 2019 March Forecast revenue requirement included in Oregon customer rates of $0.79 million. As discussed later in my testimony, the increase in NPSE for the 2020 March Forecast as compared to last year is largely attributable to lower expected hydro generation, which is down 14 percent compared to last year. The reduction in hydro generation is expected to be met with increased market purchased power and natural gas generation. Although market prices and natural gas prices have decreased as compared to last year,[2] the increased reliance on these resources in lieu of hydro generation increases NPSE. In addition, lower market prices reduce the Company's ability to make economic off-system sales, which also contributes to higher NPSE for the April 2020 – March 2021 test period. The reduced off-system sales are reflected in the 65 percent reduction in coal-fired generation. Compared to last year, coal-fired plants have become less economic to run for surplus sales and to serve load. The reduction in coal-fired generation is also due to the cessation of operations from one unit at the North Valmy plant ("Valmy") in 2019 and the Boardman plant ("Boardman") in 2020.

[2] Market prices and natural gas prices included in last year's March Forecast were higher due to the sustained effects of the Enbridge natural gas pipeline explosion that occurred in the Pacific Northwest in October 2018.

For the October Update, the requested revenue requirement decrease is approximately $0.22 million as compared to the revenue requirement decrease of $0.18 million included in the initial October Update filing. The decrease in the October Update revenue requirement is due to an update to the Company's forecast of Energy Imbalance Market ("EIM") benefits for the April 2020 through March 2021 test period, which will be discussed later in my testimony.

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 NPSE for the 2020 March Forecast and how it compares to last year's 2019 March Forecast. My testimony concludes with the quantification of the projected revenue requirement increase and the proposed rate implementation to allocate the revenue increase to customers.

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 2020 March Forecast.
3. Exhibit 303, determination of normalized NPSE for the 2020 October Update.
4. Exhibit 304, year-over-year differences in modeled NPSE.
5. Exhibit 305, EIM benefits.
6. Exhibit 306, EIM costs.

7. Exhibit 307, October Update and March Forecast combined rate calculation.
8. Exhibit 308, revenue spread and revenue impact.

I. 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 91 water year conditions in the AURORA model and then averaging the results of all 91 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.

II. 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;

i. 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 2020 March Forecast and those used to develop the 2020 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 2020 through March 2021 test period, the following variables changed since the October APCU was prepared: (1) fuel prices and transportation costs; (2) forced outage rates; (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 ("ERMP"); (6) forward price curve; and (7) PURPA contract expenses.

A. <u>Fuel Expense</u>.

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 2019 Operations Plan was used. The March Forecast determination of NPSE includes the Company's most current coal and gas price forecasts.

Q. How do AURORA-modeled coal fuel expense and coal-fired generation for the March Forecast compare to the October Update results?

A. Total coal fuel expense included in the 2020 March Forecast is $36.7 million, compared to $40.8 million in the 2020 October Update, a decrease of 10 percent. Coal-fired generation also decreased as compared to the October Update, from 1.05 million megawatt-hours ("MWh") to 0.88 million MWh, or approximately 16 percent.

Q. How do the decreases in coal fuel expense and coal-fired generation impact cost of coal production on a per-unit basis?

A. The average cost of coal production on a per-unit basis for the March Forecast is $41.74 per MWh, compared to $38.90 per MWh for the October Update. At the plant level, the per-unit cost of production decreased at the Jim Bridger plant ("Bridger") from $39.34 per MWh to $37.67 per MWh and increased at Boardman from $26.98 per MWh to $32.48 per MWh. Valmy was not economically dispatched by AURORA for the March Forecast, whereas the October Update included 0.21 million MWh.

Q. What factors drove the changes in the per-unit cost of production at the Company's coal plants since the October Update was filed?

A. The per-unit costs of production at Bridger decreased between the October Update and the March Forecast due to a 4 percent reduction in coal costs, on a dollar per MMBtu basis. The decline in costs drove an increase in the AURORA-modeled dispatch, resulting in a lower per-unit cost of production. Conversely, Boardman coal costs increased 15 percent between the October Update and March Forecast, causing a decrease in AURORA-modeled production and resulting in a higher per-unit cost of production. Coal costs increased at Boardman due to a decrease in expected generation and associated coal volumes as the plant nears retirement, which resulted in a higher cost per MMBtu.

Q. Did the Company update its forecast of total Oil, Handling, and Administrative and General ("OHAG") expenses per the terms of the 2016 and 2017 APCU settlement stipulations?

A. Yes. Per the terms of the 2016 APCU settlement stipulation,[3] 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 OHAG expenses incurred at each of the coal plants.

Per the terms of the 2017 APCU settlement stipulation ("2017 Stipulation"),[4] the Company is to annually update its proportional share of total forecast OHAG expense incurred at each of the coal plants as part of the March Forecast filing. The Company's OHAG forecast is calculated 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. For the 2020 March Forecast, Idaho Power updated the OHAG forecast using the 2017-2019 historical average of actual OHAG costs, with a growth rate equal to the 2015-2019 historical average growth rate. The forecast of total OHAG expenses for Bridger, Boardman, and Valmy are displayed on lines 6, 12, and 18 of Exhibit 302, respectively.

Q. Does Idaho Power's 2020 March Forecast account for revenues received from or expenses paid to NV Energy (its ownership partner in the Valmy plant) for use of the Company's unused capacity or the Company's use of NV Energy's unused capacity?

---

[3] *In the Matter of Idaho Power Company's 2016 Annual Power Cost Update*, Docket No. UE 301, Stipulation/7 (May 11, 2016).

[4] *In the Matter of Idaho Power Company's 2017 Annual Power Cost Update*, Docket No. UE 314, Stipulation/7 (April 28, 2017).

A. Yes. Per the terms of the 2017 Stipulation,[5] Idaho Power agreed to include the three-year historical average of actual net balances associated with ownership partner use of unused capacity at Valmy as an offset or expense to total NPSE. The Company is to update the three-year historical average as part of the March Forecast. For the 2020 March Forecast, the 2017-2019 historical average net revenue paid to Idaho Power is $115,498 on a system-wide basis, associated with NV Energy's dispatch of Idaho Power's unused capacity at Valmy. As shown on line 19 of Exhibit 302, this amount has been reflected as an offset to NPSE for Valmy for the 2020 March Forecast.

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 $2.71 per MMBtu, while the gas price forecast used for the March Forecast for Henry Hub was $2.35 per MMBtu, a decrease of $0.36 per MMBtu.

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 $2.98 per MMBtu applied to a Sumas basis of $0.13 per MMBtu equals a Sumas gas price of $3.11 per MMBtu ($2.98 + $0.13 = $3.11). The Company develops a separate gas price for its natural gas units based upon the Henry Hub gas price forecast, referred to as the Idaho Citygate price.

Q. Please explain the Idaho Citygate price.

[5] *Id.* at 3.

A. The Idaho Citygate price is representative of the gas price delivered to Idaho Power's natural gas units. The Idaho Citygate price is based on the Henry Hub price and applies adjustments for Sumas basis and transport costs.

Q. How does the Idaho Citygate price for the 2020 March Forecast compare to last year?

A. The average Idaho Citygate price for the 2020 March Forecast is $2.35 per MMBtu compared to $3.17 per MMBtu for the 2019 March Forecast, a 27 percent decrease. The decrease in the Idaho Citygate price for the 2020 March Forecast is due to a return to normal conditions after the Enbridge natural gas pipeline explosion. As briefly described earlier, natural gas prices included in the 2019 March Forecast were unusually high due to the pipeline explosion that occurred in October 2018. The Enbridge pipeline runs from British Columbia and connects to the Northwest Pipeline system, which feeds the Pacific Northwest with natural gas. Due to the October 2018 explosion, natural gas storage in the Pacific Northwest was down 40 percent last year. Additionally, the pipeline was expected to take months to repair and return to 100 percent deliverability, which caused significant increases in natural gas and electric market prices. Now that the pipeline has been restored, prices have returned to more normal levels.

B. <u>PURPA Expense</u>.

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

A. The October Update included 345 average megawatts ("aMW") of available PURPA generation, whereas the PURPA generation included in the March Forecast is 339 aMW, a decrease of 6 aMW, or 1.7 percent, since the October Update.

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 $218.2 million compared to $223.5 million included in the October Update, a decrease of $5.3 million, or 2.4 percent. The decrease in PURPA generation and expense is primarily due to the unexpected termination of an existing 4.5 MW biomass project on November 30, 2019.

Q. Does the PURPA forecast included in the 2020 March Forecast include a Contract Delay Rate ("CDR") adjustment per the terms of the 2018 APCU settlement stipulation?

A. Yes. Per the terms of the settlement stipulation approved by Order No. 18-170 in the Company's 2018 APCU, Docket No. UE 333 ("2018 Stipulation"),[6] Idaho Power applied a CDR adjustment to the PURPA forecast included in the March Forecast of the APCU. The CDR was calculated based on a three-year average of differences in scheduled operation date and actual operation date for historical PURPA projects. The CDR was then applied to the expected on-line date for all new PURPA projects included in the PURPA forecast for the 2020 March Forecast.

The 2020 March Forecast includes one new PURPA project. In compliance with the 2018 Stipulation, the Company calculated a three-year average CDR of 99 days. Applying the CDR of 99 days to the scheduled operation date for the new project resulted in CDR-adjusted operation date of December 8, 2020, as opposed to the actual scheduled operation date of August 31, 2020. Accordingly, the forecast generation and expense associated with this project are included in the PURPA forecast for the 2020 March Forecast beginning in December 2020 rather than August 2020. The Company will submit a workpaper to support its CDR calculation, as well as the PURPA forecast for the 2020 March Forecast.

C. <u>Normalized Load</u>.

[6] *In the Matter of Idaho Power Company's 2018 Annual Power Cost Update*, Docket No. UE 333, Stipulation/8 (May 1, 2018).

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

A. The forecast of system normalized load used for both the October Update and the March Forecast was 1,860 aMW. Although there was not a change in system normalized load, there was a reallocation of normalized load and billed sales by jurisdiction between the October Update and March Forecast, which resulted in a decrease in the Oregon jurisdictional share of NPSE. This will be discussed in further detail later in testimony.

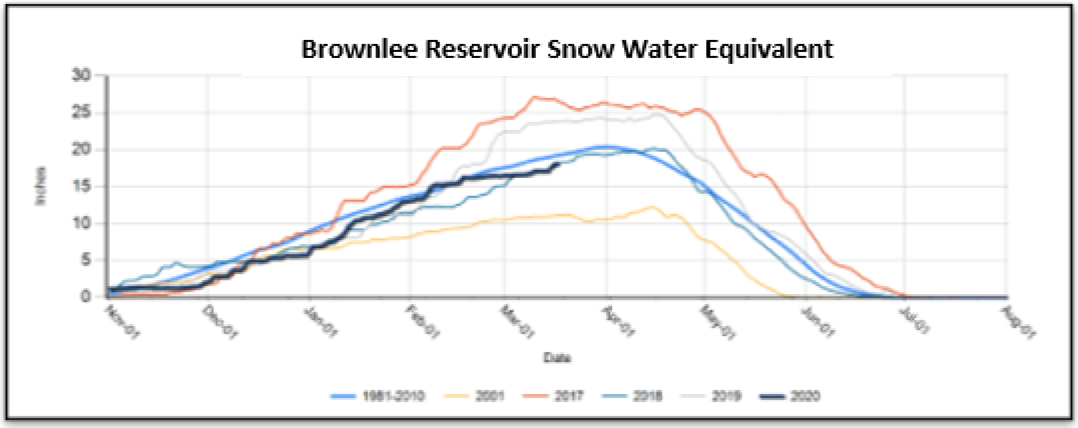
D. Hydro Forecast.

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 4, 2020, forecast. The forecast has expected inflows into Brownlee Reservoir for April through July of 4.46 million acre-feet ("MAF"), or 82 percent of 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 included expected inflows into Brownlee Reservoir for April through July of 5.43 MAF compared to this year's forecast of 4.46 MAF, reflecting an 18 percent decrease. Expected inflows into Brownlee Reservoir were higher for last year's March Forecast as a result of better snowpack conditions, which provide for sustained runoff and increased hydro generation during the spring and summer months. The following graph illustrates snow water equivalent, in inches, for the basin above Brownlee Reservoir as of March 17, 2020.



The graph reveals the decrease in snowpack conditions for 2020 as compared to last year, which is driving the reduction in expected inflows and ultimately forecast hydro generation.

Q. How does the change 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 7.2 million MWh compared to 8.4 million MWh in last year's March Forecast, a 14 percent decrease.

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 (91 water years) for the October Update was 8.8 million MWh. The hydro generation forecasted for this year's March Forecast is 7.2 million MWh, a decrease of 1.6 million MWh or 18 percent as compared to the October Update, which suggests that the expected hydro generation for the March Forecast is well below normal.

E. Known Power Purchases and Surplus Sales.

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

A. Yes. The Company includes known power purchases and surplus sales resulting from the Company's ERMP and incorporates those amounts as net hedges on Exhibit 302, lines 42 and 43, as directed by Order No. 08-238. Known power purchases and surplus sales are not included in the October Update of the APCU.

F. 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 6, 2020, Mid-Columbia Heavy Load (HL) and Light Load (LL) forward price curve for the April 2020 through March 2021 test period the Company used for the March Forecast, as directed by Order No. 08-238.

III. 2020 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 2020 through March 2021 test year.

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 2020 through March 2021 test period, with updated fuel prices, normalized load, updated stream flow conditions, updated power purchases, and surplus sales from the Company's ERMP (net hedges), market purchased power and surplus sales re-priced, and updated PURPA contract expenses. The March Forecast of NPSE without PURPA expenses is $210.6 million. When PURPA expenses of $218.2 million and EIM benefits of $16.5 million are included, total NPSE for the March Forecast is $412.3 million. A discussion of EIM benefits is included later in testimony.

Q. How does the 2020 March Forecast of NPSE compare to last year's March Forecast of NPSE?

A. The 2020 March Forecast of NPSE is $412.3 million, or $17.4 million more than the 2019 March Forecast of NPSE of $394.9 million.[7]

Q. How does the modeled generation in the 2020 March Forecast compare to last year's March Forecast?

A. At a high-level, a reduction in expected hydro generation is being met with increased market purchased power and natural gas generation. Although market prices have decreased as compared to last year's March Forecast, limiting the impact of increased market purchased power on NPSE, the reduction in prices is reducing the Company's ability to make economic off-system sales, particularly with coal-fired generation. The reduction in coal-fired generation is also a result the cessations of operations in Valmy Unit 1 in December 2019 and Boardman in October 2020. Exhibit 304 compares the AURORA-developed results, the re-pricing of purchased power and surplus sales, and the differences between the 2020 March Forecast and 2019 March Forecast.

Q. What are some of the differences in resource dispatch as shown in Exhibit 304?

A. Column H of Exhibit 304 shows the following: a decrease in coal fuel expense of $52.6 million associated with a 1.63 million MWh decrease in generation; an increase in natural gas expense of $8.4 million associated with an increase of 1.03 million MWh in generation; an increase in market purchased power expenses of $38.4 million associated with an increase of 1.49 million MWh; an increase in PPA expense of $1.3 million associated with an increase of 4,028 MWh; a decrease in PURPA expenses of $2.2 million associated with an increase of 5,639 MWh; and, finally, a decrease in surplus sales revenue of $25.5 million associated with a decrease of 0.47 million MWh.

[7] Final NPSE as shown in Exhibit No. 2 of the 2019 APCU Settlement Stipulation, Docket No. UE 350 (May 8, 2019).

Q. How does expected generation change from the 2019 March Forecast to the 2020 March Forecast?

A. To illustrate the changes in generation, columns D (2019) and F (2020) of Exhibit 304 calculate the percentage of generation compared to total system load. For the 2020 March Forecast, hydro generation decreased from 52 percent to 44 percent; coal generation decreased from 16 percent to 5 percent; natural gas generation increased from 14 percent to 21 percent; market purchased power increased from 4 percent to 13 percent; PPA generation decreased from 4 percent to 3 percent; PURPA generation was unchanged at 18 percent; and, lastly, surplus sales decreased from 8 percent to 5 percent. This comparison between resource type and total system load shows that decreased hydro generation is being met with market purchased power and natural gas generation. The reduction in market prices is also driving a reduction in the economic dispatch of coal-fired plants and surplus sales.

Q. Are the relative changes in expenses between resource types consistent with the changes in output?

A. Yes. The relative changes in expenses between resource types are consistent with the changes in output. The changes in expenses shown in columns D (2019) and F (2020) of Exhibit 304 are as follows: coal fuel expense decreased from 23 percent to 9 percent of total expense; natural gas increased from 16 percent to 18 percent; market purchased power increased from 7 percent to 16 percent; PPA expense decreased form 12 percent to 11 percent; PURPA expense decreased from 56 percent to 53 percent; and surplus sales revenue decreased from negative 9 percent to negative 3 percent. Exhibit 304 demonstrates that the majority of movement in expenses is related to coal, market power purchases and sales, and natural gas.

Q. Please summarize the factors driving the change in NPSE as compared to last year's March Forecast.

A. The average per-unit cost of natural gas generation for the 2020 March Forecast is $21.66 per MWh compared to last year's March Forecast average per-unit cost of $27.60 per MWh, a 22 percent decrease. The average AURORA-modeled market purchase price (before re-pricing) for the 2020 March Forecast is $31.22 per MWh, compared to $35.15 per MWh for last year, an 11 percent decrease. Due to the reductions in natural gas prices and electric market prices, the Company's reliance on coal-fired generation is expected to decrease, whereby the average per-unit cost varies from $32.48 per MWh to $37.67 per MWh. At the same time, lower market prices have decreased the Company's expectation of economic off-system sales, resulting in an increase to NPSE as compared to last year. The average AURORA-modeled market sales prices (before re-pricing) for the 2020 APCU is $16.10 per MWh, as compared to $21.51 for the 2019 March Forecast.

Q. How does the re-pricing of purchased power and surplus sales change purchased power expenses and surplus sales revenues as modeled by AURORA?

A. As shown in columns I and J of Exhibit 304, for this year's March Forecast, re-pricing of market purchases and sales results in a net decrease in NPSE of $1.2 million. The re-pricing of purchased power decreased the average market purchase price of $31.22 per MWh (as modeled in AURORA) to $29.52 per MWh, resulting in a $3.7 million decrease in NPSE. The re-pricing of surplus sales decreased the average market sales price of $16.10 per MWh (as modeled in AURORA) to $13.14 per MWh, resulting in a decrease in surplus sales revenue of $2.5 million.

A. <u>EIM Costs and Benefits</u>.

Q. Has the Company adjusted the NPSE amounts included in the 2020 APCU to reflect Idaho Power's participation in the Western EIM?

A. Yes. The NPSE requested for approval in the 2020 APCU includes both the incremental benefits and costs associated with Idaho Power's participation in the Western EIM. Because the cost-savings benefits associated with EIM participation will be reflected as decreased NPSE, the Company believes it is appropriate to include an estimate of both the incremental benefits and the incremental costs required for participation as part of this APCU.

Q. What level of EIM benefits is Idaho Power proposing to include in the 2020 APCU?

A. Idaho Power is proposing to include $16.5 million in system EIM benefits as an offset to NPSE in the 2020 APCU, as shown on Line 46 of Exhibit 302. On an Oregon allocated basis, the EIM benefits to be included in the 2020 APCU total $749,691.

Q. How does this compare to the level of EIM benefits included in the 2020 October Update?

A. The forecast of EIM benefits included in the 2020 October Update was $16.2 million, $751,388 on an Oregon allocated basis, and base NPSE totaled $376.3 million. With the updated EIM benefits estimate of $16.5 million, normalized NPSE included in the October Update totals $376.0 million. The Company has included the updated estimate of EIM benefits as an offset to forecast NPSE for the October Update, as shown in Exhibit 303.

Q. What is driving the change in the EIM benefits forecast between the 2020 APCU October Update and the March Forecast filings?

A. The change in the EIM benefits forecast between the 2020 APCU October Update and March Forecast filings is due to updating the benefit calculation with the most recent data available as well as implementing a methodology change proposed by Staff in opening testimony.

Q. Please describe the data used in the EIM benefit calculation.

A. As described in my opening testimony, Idaho Power's EIM benefit calculation utilizes the California Independent System Operator ("CAISO") report of EIM benefits as a starting point, and then accounts for necessary adjustments to quantify ongoing cost savings benefits specific to Idaho Power's participation in the EIM. These adjustments include a modification to the CAISO methodology as it pertains to the hydro pricing cost structure, and an adjustment for third-party load included in the Company's balancing area.[8] The Company updated its EIM benefit calculation using the most recent 12-months of EIM benefit data from CAISO, which includes data for March 2019 – February 2020.[9] The Company also updated the adjustment for third-party load included in Idaho Power's balancing area based on the most recent 12-months of data.

Q. Please describe the methodology change made to Idaho Power's EIM benefit forecast.

A. In opening testimony, Staff proposed use of a modified version of the Company's EIM benefit forecast methodology and recommended two alterations to the hydro net import / export adjustment. First, Staff proposed use of a Mid-Columbia mid-market electricity price to assign a value to the hydro net imports / exports rather than a bilateral sales price. Second, Staff proposed that the Company's hydro net import / export adjustment be assessed on an hourly basis rather than a daily basis.[10] Idaho Power has incorporated these changes into the EIM benefit forecast.

---

[8] Idaho Power/100, Blackwell 14-20.

[9] Due to this year's March Forecast filing date of March 24, 2020, and receipt of CAISO's February 2020 EIM benefit data on March 18, 2020, Idaho Power did not have sufficient time to validate the CAISO EIM benefits and conduct the hydro adjustments through Power Settlements to determine EIM benefits specific to the Company. As a result, Idaho Power's EIM Benefit Forecast for the 2020 APCU uses CAISO EIM benefit data for February 2020. The Company intends to finalize the calculation of February 2020 EIM benefits specific to Idaho Power, for inclusion in the 2020 APCU, by March 31, 2020.

[10] Staff/100, Enright/18.

Q. Has the Company made any other changes to its EIM benefit forecast methodology since the 2020 October Update filing?

A. No. Aside from the adjustments described above, Idaho Power has not made any other changes to the EIM benefit forecast methodology presented in the 2020 October Update filing. Exhibit 305 presents Idaho Power's EIM benefit forecast for the 2020 APCU. Exhibit 305 demonstrates Idaho Power's adjustments to the CAISO EIM benefit methodology as it pertains to the hydro pricing cost structure as well as third-party loads in the Company's BAA that are included in CAISO's benefit calculation.

Q. Did the Company update the estimated EIM costs to be included in the 2020 APCU?

A. Yes. The Company updated the annual revenue requirement associated with the EIM-related costs to be included in the 2020 APCU. The EIM-related costs included in the 2020 APCU consist of the annual return on net rate base from the capital investment required to participate in the Western EIM, depreciation expense, and ongoing incremental operations and maintenance expenses. On an Oregon-allocated basis, the revenue requirement associated with EIM costs to be included in the 2020 APCU is $150,390, as shown in Exhibit 306, which is $4,677 more than the estimate included in the October Update.

B. <u>Per-Unit Cost Calculation and Quantification of the Revenue Requirement Impact</u>.

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 2020 through March 2021 test period of 15,012,868 MWh (line 48). Based upon test period sales, the cost per-unit for the March Forecast is $27.47 per MWh ($412.3 million / 15.013 million MWh = $27.47 per MWh) (lines 47, 48, and 49).

Q. How does this year's March Forecast unit cost per MWh compare to last year's March Forecast unit cost per MWh?

A. The 2019 March Forecast unit cost per MWh was $26.62 per MWh ($394.9 million / 14.837 million MWh = $26.62 per MWh), compared to this year's March Forecast unit cost of $27.47 per MWh.

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

A. Exhibit 307 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 $25.05 per MWh. Lines 4-6 show the calculation for the March Forecast unit cost of $27.47 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 divides line 9 by line 4 to calculate the March Forecast rate of $2.30 per MWh.

Q. How does the $2.30 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 2019 through March 2020 test period was $1.16 per MWh, as compared to this year's April 2020 through March 2021 test period rate of $2.30 per MWh, an increase of $1.14 per MWh.

Q. How is the revenue requirement for the March Forecast calculated using the March Forecast rate unit cost of $2.30 per MWh?

A. The revenue requirement for the March Forecast is calculated by multiplying the March Forecast rate of $2.30 per MWh by the loss-adjusted Oregon jurisdictional sales for the April 2020 through March 2021 test period of 683,811.053 MWh, resulting in a revenue requirement of approximately $1.57 million, as shown on page 2 of Exhibit

308, line 1. Under the current March Forecast rate of $1.16 per MWh, the revenue requirement included in Oregon customer rates is approximately $0.79 million. As such, the proposed 2020 March Forecast rate of $2.30 per MWh will result in a revenue requirement increase of $0.78 million compared to what is currently being collected through Oregon customer rates.

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

A. Yes. The Company revised the revenue requirement for the October Update to align with the loss-adjusted sales that were used for the March Forecast filing and to update estimates of EIM benefits and costs.

The practice of updating the loss-adjusted sales for the October Update revenue requirement is consistent with the method applied in the last eight APCU filings in Docket Nos. UE 242, UE 257, UE 279, UE 293, UE 301, UE 314, UE 333 and UE 350. The April 2020 through March 2021 loss-adjusted Oregon jurisdictional sales for the October Update were 695,285.576 MWh, whereas the loss-adjusted Oregon jurisdictional sales for the March Forecast are 683,811.053, a decrease of 11,475.523 MWh. The change in the loss-adjusted sales, as well as the updated estimates of EIM benefits and costs, decreases the October Update revenue requirement from an initial decrease of $176,943 to a decrease of $222,647. Exhibit 308 contains the revised October Update revenue requirement.

IV. RATE IMPLEMENTATION

Q. What method of allocation are you proposing to spread the revenue requirement increase associated with the 2020 APCU to the various customer classes?

A. The Company proposes to allocate the revenue requirement associated with the 2020 APCU according to the revenue spread methodology agreed upon in the 2018 Stipulation. The 2018 Stipulation established a revenue spread methodology whereby the APCU revenue requirement is allocated to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the test period. Additionally, any rate increases resulting from application of this revenue spread methodology as applied to a customer class will be capped at 3 percent above the overall average rate increase on a percentage of total revenue basis. In this case, the overall average rate change as a percentage of total revenue is an increase of 1.01 percent; therefore, any rate increases applied to individual customer classes will be capped at 4.01 percent. The proposed revenue spread resulting from the application of the stipulated methodology is shown in Exhibit 308.

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 308 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 page 6 of Exhibit 308, the overall revenue impact of this year's combined October Update and March Forecast is an increase of $0.56 million or 1.01 percent overall. The $0.56 million increase reflects a decrease of $0.22 million in base rate revenues associated with the October Update and a $0.78 million increase in Schedule 55 revenues associated with the March Forecast, as compared to what is currently included in Oregon customers' rates related to the 2019 APCU.

Q. Does the Company intend to provide supporting workpapers for the 2020 March Forecast to Staff and CUB?

A. Yes. Idaho Power will provide its supporting workpapers to Staff and CUB within five business days of filing the 2020 March Forecast.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Mid-Columbia Price Curve for April 2020 – March 2021

March 24, 2020

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	**3/6/2020**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**
2	**mc HL**	17.50	12.25	16.30	34.40	45.45	34.00	26.50	27.70	38.65	36.40	33.05	23.35
3	**mc LL**	13.50	5.80	6.50	18.25	26.05	25.50	22.35	22.75	32.10	29.70	26.75	18.35
4	**Reallocated Prices**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**
5	**HL PP**												
6	103.9%	18.18	12.73	16.94	35.74	47.22	35.33	27.53	28.78	40.16	37.82	34.34	24.26
7	**LL PP**												
8	107.1%	14.46	6.21	6.96	19.55	27.90	27.31	23.94	24.37	34.38	31.81	28.65	19.65
9	**HL SS**												
10	96.4%	16.87	11.81	15.71	33.16	43.81	32.78	25.55	26.70	37.26	35.09	31.86	22.51
11	**LL SS**												
12	93.4%	12.61	5.42	6.07	17.05	24.33	23.82	20.87	21.25	29.98	27.74	24.98	17.14

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

March Forecast of Expected Power Supply Costs for April 1, 2020 – March 31, 2021

March 24, 2020

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2020 -- MARCH 31, 2021 (One Hydro Condition)
Repriced Using UE 195 Settlement Methodology - 2020 March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	1,016,249.5	898,120.9	789,244.5	595,550.9	477,684.6	454,354.2	449,755.8	381,688.0	437,427.6	466,072.8	479,971.3	718,709.8	7,164,829.9
	Bridger													
2	Energy (MWh)	-	-	-	172,323.5	188,223.6	22,041.5	3,061.1	86,123.2	217,239.4	108,464.9	19,917.7	-	817,394.8
3	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ -	$ 6,001.8	$ 6,558.2	$ 768.3	$ 110.2	$ 3,034.9	$ 7,523.3	$ 3,990.9	$ 736.0	$ -	$ 28,723.6
4	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ 180.9	$ 197.6	$ 23.1	$ 3.2	$ 90.4	$ 228.1	$ 113.9	$ 20.9	$ -	$ 858.3
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ 5,820.9	$ 6,360.5	$ 745.2	$ 107.0	$ 2,944.4	$ 7,295.2	$ 3,877.0	$ 715.1	$ -	$ 27,865.3
6	IPC Share of OHAG Expense ($ x 1000)	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 243.6	$ 2,923.0
7	Total Expense ($ x 1000)	$ 243.6	$ 243.6	$ 243.6	$ 6,064.5	$ 6,604.1	$ 988.8	$ 350.6	$ 3,188.0	$ 7,538.8	$ 4,120.6	$ 958.7	$ 243.6	$ 30,788.4
	Boardman													
8	Energy (MWh)	-	-	2,213.9	17,210.0	20,755.9	11,991.9	9,655.7	-	-	-	-	-	61,827.3
9	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ 71.7	$ 534.0	$ 637.7	$ 377.4	$ 310.4	$ -	$ -	$ -	$ -	$ -	$ 1,931.2
10	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 1.4	$ 10.5	$ 12.7	$ 7.3	$ 5.9	$ -	$ -	$ -	$ -	$ -	$ 37.7
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 70.4	$ 523.5	$ 625.0	$ 370.0	$ 304.5	$ -	$ -	$ -	$ -	$ -	$ 1,893.5
12	IPC Share of OHAG Expense ($ x 1000)	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ 16.4	$ -	$ -	$ -	$ -	$ -	$ 114.9
13	Total Expense ($ x 1000)	$ 16.4	$ 16.4	$ 86.8	$ 540.0	$ 641.5	$ 386.5	$ 320.9	$ -	$ -	$ -	$ -	$ -	$ 2,008.5
	Valmy													
14	Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
15	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	IPC Share of OHAG Expense ($ x 1000)	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 334.9	$ 4,018.9
19	Usage Charges Paid to IPC ($ x 1000)	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 115.5
20	Total Expense ($ x 1000)	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 325.3	$ 3,903.4
	Langley Gulch													
21	Energy (MWh)	138,456.6	202,471.5	194,723.1	199,049.8	199,049.8	194,745.6	199,479.0	193,242.9	200,988.2	211,641.6	180,891.3	160,894.0	2,275,633.3
22	Expense ($ x 1000)	$ 1,592.1	$ 2,070.6	$ 2,134.3	$ 2,532.0	$ 2,913.8	$ 2,636.3	$ 3,085.1	$ 4,150.6	$ 5,569.9	$ 5,197.2	$ 3,925.2	$ 2,870.0	$ 38,677.1
	Danskin													
23	Energy (MWh)	19,734.1	70,927.6	82,510.4	143,114.8	129,250.1	125,274.0	59,870.3	12,400.8	1,808.1	9,971.1	11,821.4	11,670.2	678,352.9
24	Expense ($ x 1000)	$ 390.5	$ 1,270.7	$ 1,595.8	$ 3,223.0	$ 3,315.8	$ 2,933.4	$ 1,579.1	$ 436.7	$ 81.0	$ 397.5	$ 421.9	$ 343.1	$ 15,988.4
	Bennett Mountain													
25	Energy (MWh)	9,565.1	40,873.8	54,834.7	88,389.0	79,713.8	78,874.3	31,372.6	6,933.2	352.1	4,410.1	6,164.8	6,087.4	407,570.9
26	Expense ($ x 1000)	$ 190.3	$ 733.5	$ 1,050.6	$ 1,943.6	$ 1,994.6	$ 1,830.7	$ 822.9	$ 246.9	$ 16.0	$ 178.4	$ 221.9	$ 182.0	$ 9,411.4
27	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 688.6	$ 711.2	$ 778.6	$ 804.2	$ 804.2	$ 778.6	$ 711.2	$ 688.6	$ 711.2	$ 711.2	$ 643.4	$ 711.2	$ 8,742.6
	Purchased Power (Excluding PURPA)													
28	Market Energy (MWh)	1,338.7	661.2	86,033.9	201,858.6	300,987.1	136,678.5	145,765.2	243,803.9	309,563.0	372,772.1	239,537.9	53,447.3	2,092,447.4
29	Elkhorn Wind Energy (MWh)	26,836.0	26,268.6	24,879.8	26,854.8	23,393.8	21,207.8	22,955.8	28,626.4	28,597.0	28,064.8	26,555.2	25,454.9	309,694.6
30	Neal Hot Springs Energy (MWh)	15,249.6	11,952.5	11,189.5	9,323.4	9,575.2	12,688.0	16,619.5	18,383.0	19,941.4	18,374.9	17,111.0	17,550.7	177,958.7
31	Raft River Geothermal Energy (MWh)	7,226.9	5,523.0	6,113.3	6,479.3	6,007.6	6,426.7	6,388.3	6,929.7	7,654.5	7,785.3	6,843.1	7,352.7	80,730.6
32	Total Energy Excl. PURPA (MWh)	50,651.2	44,405.3	128,216.4	244,516.0	339,963.7	177,001.0	191,728.8	297,743.0	365,755.9	426,997.1	290,047.2	103,805.7	2,660,831.3
33	Market Expense ($ x 1000)	$ -	$ -	$ 1,014.4	$ 5,218.6	$ 9,463.9	$ 4,239.9	$ 3,742.0	$ 6,454.5	$ 11,313.8	$ 12,432.5	$ 7,104.9	$ 1,055.5	$ 62,040.0
34	Elkhorn Wind Expense ($ x 1000)	$ 1,306.4	$ 1,278.8	$ 1,647.8	$ 2,134.4	$ 1,859.3	$ 1,404.6	$ 1,520.4	$ 2,275.2	$ 2,272.9	$ 1,914.6	$ 1,811.6	$ 1,276.3	$ 20,702.2
35	Neal Hot Springs Expense ($ x 1000)	$ 1,324.1	$ 1,037.8	$ 1,325.5	$ 1,325.3	$ 1,361.1	$ 1,503.0	$ 1,968.7	$ 2,613.2	$ 2,834.7	$ 2,214.5	$ 2,062.2	$ 1,550.4	$ 21,120.7
36	Raft River Geothermal Expense ($ x 1000)	$ 365.4	$ 279.2	$ 420.5	$ 534.9	$ 495.9	$ 442.1	$ 439.5	$ 572.0	$ 631.9	$ 538.7	$ 473.5	$ 374.0	$ 5,567.7
37	Total Expense Excl. PURPA ($ x 1000)	$ 2,995.9	$ 2,595.8	$ 4,408.3	$ 9,213.2	$ 13,180.3	$ 7,589.6	$ 7,670.5	$ 11,914.9	$ 17,053.2	$ 17,100.4	$ 11,452.3	$ 4,256.2	$ 109,430.5
	Surplus Sales													
38	Energy (MWh)	427,655.3	266,951.6	53,216.0	9,169.5	1,987.6	2,905.2	10,547.8	782.9	38.5	24.5	476.0	76,230.0	849,984.8
39	Revenue Including Transmission Expenses ($ x 1000)	$ 6,543.3	$ 2,476.5	$ 669.5	$ 269.0	$ 80.2	$ 87.6	$ 240.6	$ 19.9	$ 1.4	$ 0.8	$ 14.3	$ 1,616.7	$ 12,020.0
40	Transmission Expenses ($ x 1000)	$ 427.7	$ 267.0	$ 53.2	$ 9.2	$ 2.0	$ 2.9	$ 10.5	$ 0.8	$ 0.0	$ 0.0	$ 0.5	$ 76.2	$ 850.0
41	Revenue Excluding Transmission Expenses ($ x 1000)	$ 6,115.7	$ 2,209.6	$ 616.3	$ 259.8	$ 78.3	$ 84.7	$ 230.1	$ 19.1	$ 1.3	$ 0.8	$ 13.8	$ 1,540.5	$ 11,170.0
	Net Hedges													
42	Energy (MWh)	-	-	38,000.0	55,440.0	11,232.0	-	-	-	-	-	-	-	104,672.0
43	Cost($ X 1000)	$ -	$ -	$ 250.0	$ 1,873.2	$ 702.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,825.2
44	Net Power Supply Expenses ($ x 1000)	$ 327.0	$ 5,757.6	$ 10,257.1	$ 26,259.1	$ 30,403.4	$ 17,384.4	$ 14,635.5	$ 20,931.9	$ 31,294.1	$ 28,029.8	$ 17,934.8	$ 7,390.8	$ 210,605.5
45	PURPA ($ x 1000)	$ 17,750.0	$ 18,265.2	$ 23,096.0	$ 25,142.5	$ 24,024.1	$ 17,981.0	$ 16,195.2	$ 16,851.4	$ 15,883.8	$ 13,985.5	$ 15,133.3	$ 13,875.0	$ 218,183.1
46	EIM Benefits													$ 16,459.25
47	Total Net Power Supply Expenses ($ x 1000)	$ 18,077.0	$ 24,022.7	$ 33,353.1	$ 51,401.6	$ 54,427.5	$ 35,365.4	$ 30,830.7	$ 37,783.4	$ 47,177.9	$ 42,015.3	$ 33,068.1	$ 21,265.8	$ 412,329.3
48	Sales at Customer Level (In 000s MWH)	1,033.794	1,091.012	1,265.207	1,548.646	1,616.825	1,436.194	1,123.870	1,039.822	1,167.969	1,311.961	1,248.050	1,129.515	15,012.868
49	Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
50	Unit Cost / MWH (for PCAM)	$17.49	$22.02	$26.36	$33.19	$33.66	$24.62	$27.43	$36.34	$40.39	$32.02	$26.50	$18.83	$27.47
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
51	Portion of Purchased Power considered HL Purchases	0.00%	0.00%	48.42%	38.94%	18.34%	46.29%	48.22%	47.77%	37.53%	25.67%	17.78%	2.06%	
52	Purchased Power HL Price	18.18	12.73	16.94	35.74	47.22	35.33	27.53	28.78	40.16	37.82	34.34	24.26	
53	Portion of Surplus Sales considered HL Surplus Sales	63.17%	60.39%	67.51%	76.25%	82.34%	70.87%	41.49%	76.12%	70.80%	86.08%	73.04%	75.78%	
54	Surplus Sales HL Price	16.87	11.81	15.71	33.16	43.81	32.78	25.55	26.70	37.26	35.09	31.86	22.51	
	Light Load													
55	Portion of Purchased Power considered LL Purchases	0.00%	0.00%	51.58%	61.06%	81.66%	53.71%	51.78%	52.23%	62.47%	74.33%	82.22%	97.94%	
56	Purchased Power LL Price	14.46	6.21	6.96	19.55	27.90	27.31	23.94	24.37	34.38	31.81	28.65	19.65	
57	Portion of Surplus Sales considered LL Surplus Sales	36.83%	39.61%	32.49%	23.75%	17.66%	29.13%	58.51%	23.88%	29.20%	13.92%	26.96%	24.22%	
58	Surplus Sales LL Price	12.61	5.42	6.07	17.05	24.33	23.82	20.87	21.25	29.98	27.74	24.98	17.14	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

October Update of Normalized Power Supply Costs for April 1, 2020 – March 31, 2021

March 24, 2020

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR APRIL 1, 2020 -- MARCH 31, 2021 (Multiple Gas Prices/91 Hydro Year Conditions)
Repriced Using UE 195 Settlement Methodology - 2020 October Update
AVERAGE

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	884,062.2	979,144.2	962,295.5	712,587.6	604,327.1	541,752.0	525,094.3	455,116.8	674,522.3	826,467.3	795,636.9	843,400.6	8,804,407.0
	Bridger													
2	Energy (MWh)	254.3	-	7,165.3	127,648.4	138,388.2	45,743.0	14,715.1	106,370.6	161,793.8	72,848.4	31,317.5	6,636.5	712,881.1
3	Expense ($ x 1000)	$ 270.2	$ 261.0	$ 513.0	$ 4,669.8	$ 5,074.5	$ 1,864.2	$ 784.7	$ 3,987.8	$ 5,838.0	$ 2,869.6	$ 1,407.1	$ 504.6	$ 28,044.7
	Boardman													
4	Energy (MWh)	4,384.8	2,435.0	6,576.9	31,264.3	32,452.7	25,598.5	18,630.4	-	-	-	-	-	121,342.7
5	Expense ($ x 1000)	$ 136.1	$ 86.6	$ 194.9	$ 823.5	$ 853.1	$ 675.8	$ 503.5	$ -	$ -	$ -	$ -	$ -	$ 3,273.5
	Valmy													
6	Energy (MWh)	440.6	-	2,722.4	23,385.2	20,964.4	10,090.6	6,184.3	18,897.0	29,660.6	49,579.6	31,590.2	20,650.1	214,165.1
7	Expense ($ x 1000)	$ 319.9	$ 304.5	$ 395.3	$ 1,060.5	$ 986.8	$ 639.2	$ 514.9	$ 917.8	$ 1,243.2	$ 1,348.9	$ 979.4	$ 753.2	$ 9,463.6
	Langley Gulch													
8	Energy (MWh)	168,394.1	201,775.7	193,108.7	198,950.8	199,048.7	194,019.1	199,317.7	191,213.0	190,172.7	170,123.7	143,009.8	155,777.5	2,204,911.3
9	Expense ($ x 1000)	$ 2,246.1	$ 2,286.5	$ 2,220.7	$ 3,095.6	$ 3,202.8	$ 3,031.6	$ 2,970.7	$ 3,852.6	$ 4,751.3	$ 4,064.3	$ 3,093.0	$ 2,856.8	$ 37,671.9
	Danskin													
10	Energy (MWh)	29,201.8	63,773.4	81,510.0	105,061.3	98,862.6	83,832.3	65,865.8	18,112.3	5,574.5	3,385.9	4,111.3	9,790.2	569,081.3
11	Expense ($ x 1000)	$ 677.4	$ 1,275.7	$ 1,681.2	$ 2,822.5	$ 2,701.1	$ 2,244.2	$ 1,681.0	$ 577.2	$ 221.5	$ 131.0	$ 144.0	$ 298.4	$ 14,455.3
	Bennett Mountain													
12	Energy (MWh)	16,851.2	34,586.7	47,877.9	68,478.3	61,413.1	45,703.9	32,515.8	8,976.2	2,172.1	1,065.0	1,591.3	5,564.0	326,795.4
13	Expense ($ x 1000)	$ 389.8	$ 694.7	$ 979.6	$ 1,817.9	$ 1,662.0	$ 1,220.1	$ 823.8	$ 286.6	$ 86.0	$ 40.7	$ 56.1	$ 172.4	$ 8,229.8
14	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 690.0	$ 712.5	$ 690.0	$ 712.5	$ 712.5	$ 690.0	$ 712.5	$ 690.0	$ 712.5	$ 711.2	$ 643.4	$ 711.2	$ 8,388.4
	Purchased Power (Excluding CSPP)													
15	Market Energy (MWh)	8,625.2	6,344.9	67,195.2	211,395.3	231,581.3	95,535.0	57,489.5	155,349.4	102,547.2	109,959.1	43,426.8	31,816.8	1,121,265.7
16	Elkhorn Wind Energy (MWh)	26,404.6	26,527.2	25,227.4	25,865.4	22,886.0	21,015.4	23,409.4	30,182.4	27,577.6	24,216.8	24,659.9	24,425.1	302,396.9
17	Neal Hot Springs Energy (MWh)	15,249.6	11,952.5	11,189.5	9,323.4	9,575.2	12,688.0	16,619.5	18,383.0	19,941.4	18,374.9	17,111.0	17,550.7	177,958.7
18	Raft River Geothermal Energy (MWh)	4,270.5	3,263.6	3,612.4	3,828.7	3,550.0	3,797.6	3,774.9	4,094.8	4,523.1	4,600.4	4,043.7	4,344.8	47,704.4
19	Total Energy Excl. CSPP (MWh)	54,549.9	48,088.1	107,224.5	250,412.8	267,592.4	133,036.0	101,293.3	208,009.6	154,589.3	157,151.2	89,241.4	78,137.3	1,649,325.8
20	Market Expense ($ x 1000)	$ 193.4	$ 126.5	$ 1,322.4	$ 9,082.8	$ 11,276.8	$ 4,248.1	$ 1,779.8	$ 5,206.5	$ 4,130.8	$ 4,340.5	$ 1,479.5	$ 898.8	$ 44,085.9
21	Elkhorn Wind Expense ($ x 1000)	$ 1,285.4	$ 1,291.3	$ 1,670.8	$ 2,055.8	$ 1,819.0	$ 1,391.8	$ 1,550.4	$ 2,398.9	$ 2,191.9	$ 1,652.1	$ 1,682.3	$ 1,224.7	$ 20,214.3
22	Neal Hot Springs Expense ($ x 1000)	$ 1,324.1	$ 1,037.8	$ 1,325.5	$ 1,325.3	$ 1,361.1	$ 1,503.0	$ 1,968.7	$ 2,613.2	$ 2,834.7	$ 2,214.5	$ 2,062.2	$ 1,550.4	$ 21,120.7
23	Raft River Geothermal Expense ($ x 1000)	$ 215.9	$ 165.0	$ 248.5	$ 316.1	$ 293.0	$ 261.2	$ 259.7	$ 338.0	$ 373.4	$ 318.3	$ 279.8	$ 221.0	$ 3,290.0
24	Total Expense Excl. CSPP ($ x 1000)	$ 3,018.8	$ 2,620.7	$ 4,567.2	$ 12,779.9	$ 14,749.9	$ 7,404.2	$ 5,558.6	$ 10,556.6	$ 9,530.7	$ 8,525.5	$ 5,503.9	$ 3,894.9	$ 88,710.9
	Surplus Sales													
25	Energy (MWh)	336,578.4	331,143.5	159,646.4	14,767.5	3,177.3	26,890.0	64,360.5	13,348.7	20,424.3	52,206.8	105,204.7	199,036.2	1,326,784.3
26	Revenue Including Transmission Costs ($ x 1000)	$ 6,843.1	$ 5,987.0	$ 2,847.9	$ 575.2	$ 140.3	$ 1,084.1	$ 1,806.8	$ 405.7	$ 746.0	$ 1,868.7	$ 3,250.2	$ 5,098.8	$ 30,653.8
27	Transmission Costs ($ x 1000)	$ 336.6	$ 331.1	$ 159.6	$ 14.8	$ 3.2	$ 26.9	$ 64.4	$ 13.3	$ 20.4	$ 52.2	$ 105.2	$ 199.0	$ 1,326.8
28	Revenue Excluding Transmission Costs ($ x 1000)	$ 6,506.5	$ 5,655.8	$ 2,688.3	$ 560.4	$ 137.1	$ 1,057.2	$ 1,742.5	$ 392.3	$ 725.6	$ 1,816.5	$ 3,145.0	$ 4,899.8	$ 29,327.1
29	Net Power Supply Expenses ($ x 1000)	$ 1,241.9	$ 2,586.5	$ 8,553.5	$ 27,221.8	$ 29,805.8	$ 16,712.1	$ 11,807.3	$ 20,476.3	$ 21,657.6	$ 15,874.7	$ 8,681.8	$ 4,291.6	**$ 168,911.0**
30	PURPA ($ x 1000)	$ 25,591.5	$ 24,383.8	$ 18,383.1	$ 16,279.5	$ 17,799.4	$ 16,617.6	$ 14,198.7	$ 15,356.4	$ 14,025.7	$ 18,382.5	$ 19,106.4	$ 23,437.1	$ 223,561.9
31	EIM Benefits													$ 16,459.3
32	Total Net Power Supply Expenses ($ x 1000)	$ 26,833.4	$ 26,970.3	$ 26,936.7	$ 43,501.3	$ 47,605.2	$ 33,329.7	$ 26,006.0	$ 35,832.7	$ 35,683.4	$ 34,257.2	$ 27,788.2	$ 27,728.7	**$ 376,013.6**
33	Sales at Customer Level (In 000s MWH)	1,033.794	1,091.012	1,265.207	1,548.646	1,616.825	1,436.194	1,123.870	1,039.822	1,167.969	1,311.961	1,248.050	1,129.515	15,012.868
34	Hours in Month	720	744	720	744	744	720	744	721	744	744	672	743	8,760
35	Unit Cost / MWH (for PCAM)	$25.96	$24.72	$21.29	$28.09	$29.44	$23.21	$23.14	$34.46	$30.55	$26.11	$22.27	$24.55	**$25.05**
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
36	Portion of Purchased Power considered HL Purchases	**64.25%**	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	
37	Purchased Power HL Price	$24.97	$23.16	$23.51	$49.85	$55.90	$50.19	$33.15	$36.00	$43.57	$42.99	$36.75	$30.12	
38	Portion of Surplus Sales considered HL Surplus Sales	**62.70%**	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	
39	Surplus Sales HL Price	$23.17	$21.49	$21.81	$46.25	$51.86	$46.57	$30.76	$33.40	$40.43	$39.89	$34.10	$27.95	
	Light Load													
40	Portion of Purchased Power considered LL Purchases	**35.75%**	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	
41	Purchased Power LL Price	$17.85	$14.15	$12.80	$30.59	$35.75	$34.18	$27.02	$29.04	$34.36	$33.16	$29.25	$24.89	
42	Portion of Surplus Sales considered LL Surplus Sales	**37.30%**	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	
43	Surplus Sales LL Price	$15.56	$12.34	$11.16	$26.68	$31.18	$29.81	$23.56	$25.33	$29.97	$28.92	$25.51	$21.70	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Year-Over-Year March Forecast Comparison

March 24, 2020

IDAHO POWER COMPANY
YEAR OVER YEAR DIFFERENCES IN AURORA DEVELOPED NPSE
2020 MARCH FORECAST

AURORA DEVELOPED NPSE RESULTS BEFORE MARKET ENERGY RE-PRICING

GENERATION

Line No.	Resource Type	A 2019 March Forecast	B 2020 March Forecast
1	Hydro (MWh)	8,353,395	7,164,830
2	Coal (MWh)	2,505,023	879,222
3	Natural Gas (MWh)	2,335,134	3,361,557
4	Market Purchased Power (MWh)	702,375	2,197,119
5	Purchased Power Agreements (MWh)	564,356	568,384
6	PURPA (MWh)	2,967,158	2,972,797
7	Surplus Sales (MWh)	1,318,886	849,985
8	System Generation (MWh)	17,427,441	17,143,909
9	System Load (MWh)	16,108,555	16,293,924
10	System Load (aMW)	1,834	1,860

NET POWER SUPPLY EXPENSES

Line No.	Resource Type	A 2019 March Forecast	B 2020 March Forecast
11	Hydro ($ x 1000)	$ -	$ -
12	Coal ($ x 1000)	$ 89,342.1	$ 36,700.2
13	Natural Gas ($ x 1000)	$ 64,446.0	$ 72,819.5
14	Market Purchased Power ($ x 1000)	$ 24,710.4	$ 68,599.5
15	Purchased Power Agreements ($ x 1000)	$ 46,079.8	$ 47,390.6
16	PURPA ($ x 1000)	$ 220,371.1	$ 218,183.1
17	Surplus Sales ($ x 1000)	$ (28,367.5)	$ (13,683.6)
18	EIM Benefits	$ (15,120.1)	$ (16,459.3)
19	Total System ($ x 1000)	$ 401,461.8	$ 413,549.9

REPRICED USING FORWARD MARKET PRICES

GENERATION

Line No.	Resource Type	C 2019 March Forecast	D	E 2020 March Forecast	F
1	Hydro (MWh)	8,353,395	52%	7,164,830	44%
2	Coal (MWh)	2,505,023	16%	879,222	5%
3	Natural Gas (MWh)	2,335,134	14%	3,361,557	21%
4	Market Purchased Power (MWh)	702,375	4%	2,197,119	13%
5	Purchased Power Agreements (MWh)	564,356	4%	568,384	3%
6	PURPA (MWh)	2,967,158	18%	2,972,797	18%
7	Surplus Sales (MWh)	1,318,886	-8%	849,985	-5%
8	System Generation (MWh)	17,427,441		17,143,909	
9	System Load (MWh)	16,108,555	100%	16,293,924	100%
10	System Load (aMW)	1,834		1,860	

NET POWER SUPPLY EXPENSES

Line No.	Resource Type	C 2019 March Forecast	D	E 2020 March Forecast	F
11	Hydro ($ x 1000)	$ -		$ -	
12	Coal ($ x 1000)	$ 89,342.1	23%	$ 36,700.2	9%
13	Natural Gas ($ x 1000)	$ 64,446.0	16%	$ 72,819.5	18%
14	Market Purchased Power ($ x 1000)	$ 26,504.6	7%	$ 64,865.2	16%
15	Purchased Power Agreements ($ x 1000)	$ 46,079.8	12%	$ 47,390.6	11%
16	PURPA ($ x 1000)	$ 220,371.1	56%	$ 218,183.1	53%
17	Surplus Sales ($ x 1000)	$ (36,676.1)	-9%	$ (11,170.0)	-3%
18	EIM Benefits	$ (15,120.1)	-4%	$ (16,459.3)	-4%
19	Total System ($ x 1000)	$ 394,947.4	100%	$ 412,329.3	100%

DIFFERENCES

GENERATION

Line No.	G (B-A)	H (E-C)	I (C-A)	J (E-B)
1	(1,188,565)	(1,188,565)	-	-
2	(1,625,801)	(1,625,801)	-	-
3	1,026,423	1,026,423	-	-
4	1,494,745	1,494,745	-	-
5	4,028	4,028	-	-
6	5,639	5,639	-	-
7	(468,901)	(468,901)	-	-
8				
9	185,370	185,370	-	-
10	26	26	-	-

NET POWER SUPPLY EXPENSES

Line No.	G (B-A)	H (E-C)	I (C-A)	J (E-B)
11	$ -	$ -	$ -	$ -
12	$ (52,641.9)	$ (52,641.9)	$ -	$ -
13	$ 8,373.4	$ 8,373.4	$ -	$ -
14	$ 43,889.1	$ 38,360.6	$ 1,794.2	$ (3,734.3)
15	$ 1,310.8	$ 1,310.8	$ -	$ -
16	$ (2,188.0)	$ (2,188.0)	$ -	$ -
17	$ 14,683.9	$ 25,506.1	$ (8,308.6)	$ 2,513.6
18	$ (1,339.2)	$ (1,339.2)	$ -	$ -
19	$ 12,088.2	$ 17,381.9	$ (6,514.4)	$ (1,220.7)

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

EIM Benefits

March 24, 2020

IDAHO POWER COMPANY
2020 APCU October Update
Energy Imbalance Market Benefit Forecast
Based on March 2019-February 2020 Historical Data

		(A)	(B)	(C)	(D)	(E)	(F)
Year	**Month**	**CAISO Benefit**	**Zero-cost Hydro Adjustment**	**Hydro Net (Export)/Import Adjustment**	**BPA Load Share %**	**BPA Load Share Adjustment**	**Idaho Power EIM Benefit**
2019	March	$ 2,598,353	$ 2,174,390	$ (809,658.87)	7.22%	$ (98,532)	$ 1,266,200
2019	April	$ 2,028,444	$ 1,506,617	$ (196,706.68)	7.19%	$ (94,194)	$ 1,215,716
2019	May	$ 2,107,396	$ 1,674,164	$ (182,649.57)	7.17%	$ (106,932)	$ 1,384,582
2019	June	$ 4,189,491	$ 3,168,740	$ (309,000.99)	7.13%	$ (203,777)	$ 2,655,962
2019	July	$ 1,569,384	$ 1,291,997	$ (112,177.21)	7.12%	$ (84,043)	$ 1,095,777
2019	August	$ 1,518,655	$ 1,105,413	$ (46,095.30)	7.14%	$ (75,647)	$ 983,670
2019	September	$ 2,271,843	$ 1,602,086	$ (110,434.96)	7.16%	$ (106,837)	$ 1,384,814
2019	October	$ 2,471,682	$ 1,546,756	$ (152,667.04)	7.19%	$ (100,290)	$ 1,293,799
2019	November	$ 1,739,733	$ 1,239,798	$ 3,229.11	7.22%	$ (89,703)	$ 1,153,325
2019	December	$ 1,875,472	$ 1,977,501	$ (296,229.80)	7.28%	$ (122,429)	$ 1,558,842
2020	January	$ 1,661,177	$ 1,281,300	$ (50,401.56)	7.25%	$ (89,225)	$ 1,141,674
2020	February [1]	$ 1,428,668			7.26%	$ (103,778)	$ 1,324,890
Total		$ 25,460,299	$ 18,568,763	$ (2,262,793)	7.19%	$ (1,275,387)	$ 16,459,251

[1] Due to this year's March Forecast filing date of March 24, 2020, and receipt of CAISO's February 2020 EIM benefit data on March 18, 2020, Idaho Power did not have sufficient time to validate the CAISO EIM benefits and conduct the hydro adjustments through Power Settlements to determine EIM benefits specific to the Company. As a result, Idaho Power's EIM Benefit Forecast for the 2020 APCU uses CAISO EIM benefit data for February 2020. The Company intends to finalize the calculation of February 2020 EIM benefits specific to Idaho Power, for inclusion in the 2020 APCU, by March 31, 2020.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

EIM Costs

March 24, 2020

Idaho Power Company
2020 APCU
Oregon Jurisdictional EIM Revenue Requirement

2020 Calendar Year Revenue Requirement

Capital Investment	$359,935
ADIT	($16,658)
Accumulated Depreciation	($1,688)
Amortization of Other Plant	($55,296)
Net Rate Base	$286,294
Return on Rate Base	**$22,208**
O&M (On-going)	$73,050
Depreciation	$50,521
Taxes	($34,100)
Total Operating Expenses	**$89,472**
Net-to-Gross Tax Multiplier	1.347
Total Revenue Requirement	**$150,390**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

October Update and March Forecast
Combined Rate Calculation for April 2020 – March 2021

March 24, 2020

APCU Combined Rate Calculation
April 2020 - March 2021

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	15,012,868
2	Total Net Power Supply Expense	$376,013,569
3	October APCU Unit Cost ($/MWh)	$25.05
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	15,012,868
5	Total Net Power Supply Expense	$412,329,286
6	March Forecast Unit Cost ($/MWh)	$27.47
7	Sales Adjusted Forecast Power Cost Change	$36,331,140
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$34,514,583
10	**March Forecast Rate ($/MWh)**	$2.30
11	**Combined Rate ($/MWh)**	$27.35

Idaho Power/308
Witness: Nicole A. Blackwell

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 366
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

2020 APCU Revenue Spread and Revenue Impact

March 24, 2020

Idaho Power Company
Stipulated Revenue Spread
2020 October Update

Line No.		
1	2020 October Update Oregon Jurisdictional Share of Base NPSE = $25.05/MWh x 683,811.053 MWhs =	$ 17,129,467
2	Oregon Allocated EIM Costs	$ 150,390
3	**Proposed October Update APCU Revenue Requirement**	**$ 17,279,857**

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
4	**April 2020 - March 2021 Generation Level Normalized Sales (kWh)**	**736,750,725**	203,714,779	21,359,651	129,187,704	15,957,170	3,308,733	473,684	178,599,571	111,290,414	71,860,761	5,904	967,370	24,984
5	**Class Share of April 2020 - March 2021 Generation Level Normalized Sales (kWh)**	**100%**	27.65%	2.90%	17.53%	2.17%	0.45%	0.06%	24.24%	15.11%	9.75%	0.00%	0.13%	0.00%
6	**2020 October Update Class Allocated Base NPSE**	$ 17,279,857	$ 4,777,956	$ 500,972	$ 3,029,987	$ 374,262	$ 77,603	$ 11,110	$ 4,188,900	$ 2,610,221	$ 1,685,433	$ 138	$ 22,689	$ 586
7	**June 2020 - May 2021 Loss-Adjusted Normalized Sales (kWh)**	**684,994,949**	185,871,153	19,517,431	118,066,056	15,058,811	3,199,934	432,196	168,569,794	107,800,796	65,567,958	5,388	882,636	22,796
8	**Proposed APCU Base Rates for 2020 October Update ($/kWh)**	**0.025226**	**0.025706**	**0.025668**	**0.025663**	**0.024853**	**0.024252**	**0.025706**	**0.024850**	**0.024213**	**0.025705**	**0.025700**	**0.025706**	**0.025705**
9	**Proposed October Update APCU Revenue Requirement**	**$ 17,279,857**	$ 4,777,956	$ 500,972	$ 3,029,987	$ 374,262	$ 77,603	$ 11,110	$ 4,188,900	$ 2,610,221	$ 1,685,433	$ 138	$ 22,689	$ 586

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
10	**Current APCU Base Rates for 2019 October Update ($/kWh) - Order No. 19-189**	**0.025530**	0.026372	0.026342	0.026341	0.025504	0.024880	0.026372	0.025504	0.022731	0.026355	0.026366	0.026372	0.024477
11	**June 2020 - May 2021 Loss-Adjusted Normalized Sales (kWh)**	**684,994,949**	185,871,153	19,517,431	118,066,056	15,058,811	3,199,934	432,196	168,569,794	107,800,796	65,567,958	5,388	882,636	22,796
12	**Base NPSE Recovered under Current APCU Base Rates**	**$ 17,502,504**	$ 4,901,740	$ 514,125	$ 3,109,920	$ 384,065	$ 79,614	$ 11,398	$ 4,299,191	$ 2,450,459	$ 1,728,016	$ 142	$ 23,277	$ 558

Idaho Power Company
Revenue Spread Exhibit for 2020 APCU March Forecast
Stipulated Revenue Spread

Line No.		
1	**Oregon Jurisdictional Share of 2020 March Forecast NPSE = $2.30/MWh x 683,811.053 MWhs =**	**$ 1,572,765**

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
2	**April 2020 - March 2021 Generation Level Normalized Sales (kWh)**	**736,750,725**	203,714,779	21,359,651	129,187,704	15,957,170	3,308,733	473,684	178,599,571	111,290,414	71,860,761	5,904	967,370	24,984
3	**Class Share of April 2020 - March 2021 Generation Level Normalized Sales (kWh)**	**100%**	27.65%	2.90%	17.53%	2.17%	0.45%	0.06%	24.24%	15.11%	9.75%	0.00%	0.13%	0.00%
4	**2020 March Forecast Class Allocated NPSE**	$ 1,572,765	$ 434,876	$ 45,597	$ 275,781	$ 34,064	$ 7,063	$ 1,011	$ 381,262	$ 237,575	$ 153,403	$ 13	$ 2,065	$ 53
5	**June 2020 - May 2021 Loss-Adjusted Normalized Sales (kWh)**	**684,994,949**	185,871,153	19,517,431	118,066,056	15,058,811	3,199,934	432,196	168,569,794	107,800,796	65,567,958	5,388	882,636	22,796
6	**Proposed APCU Rates for 2020 March Forecast ($/kWh)**	**0.00230**	**0.00234**	**0.00234**	**0.00234**	**0.00226**	**0.00221**	**0.00234**	**0.00226**	**0.00220**	**0.00234**	**0.00234**	**0.00234**	**0.00234**
7	**Proposed March Forecast Revenue Requirement**	**$ 1,572,765**	$ 434,876	$ 45,597	$ 275,781	$ 34,064	$ 7,063	$ 1,011	$ 381,262	$ 237,575	$ 153,403	$ 13	$ 2,065	$ 53

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
8	**APCU Rates for 2019 March Forecast - Order No. 19-189 ($/kWh)**	**0.00116**	**0.00118**	**0.00118**	**0.00118**	**0.00114**	**0.00111**	**0.00118**	**0.00114**	**0.00111**	**0.00118**	**0.00118**	**0.00118**	**0.00118**
9	**June 2020 - May 2021 Loss-Adjusted Normalized Sales (kWh)**	**684,994,949**	185,871,153	19,517,431	118,066,056	15,058,811	3,199,934	432,196	168,569,794	107,800,796	65,567,958	5,388	882,636	22,796
10	**NPSE Recovered under Current March Forecast Rate**	**$ 793,835**	$ 219,450	$ 23,017	$ 139,231	$ 17,195	$ 3,564	$ 510	$ 192,474	$ 119,955	$ 77,363	$ 6	$ 1,042	$ 27

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2020

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 Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	2020 October Update Proposed Base NPSE Revenue	Total Proposed Base Revenue	2020 October Update Proposed Adjustments to Base Revenue	2020 October Update Base Revenue Percent Change	Current Billed Revenue w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	2020 March Forecast Proposed Revenue	2020 March Forecast Proposed Adjustments to Billed Revenue	2020 Composite APCU Revenue Adjustment	Proposed Total Billed Revenue	2020 Composite APCU Percent Change	Stipulated Revenue Increase Cap (4.01%)	Revenue Requirement Shortfall
	Uniform Tariff Rates:																				
1	Residential Service	1	13,474	185,871,153	$ 12,071,304	$ 4,901,740	$ 16,973,044	$ 4,777,956	$ 16,849,259	$ (123,784)	(0.73)%	$ 17,755,085	$ 219,450	$ 17,974,536	$ 434,876	$ 215,426	$ 91,642	$ 18,066,178	0.51%	$ 91,642	$ -
2	Small General Service	7	2,672	19,517,431	$ 1,492,625	$ 514,125	$ 2,006,749	$ 500,972	$ 1,993,597	$ (13,152)	(0.66)%	$ 2,093,394	$ 23,017	$ 2,116,411	$ 45,597	$ 22,580	$ 9,427	$ 2,125,839	0.45%	$ 9,427	$ -
3	Large General Secondary	9S	938	118,066,056	$ 5,823,517	$ 3,109,920	$ 8,933,436	$ 3,029,987	$ 8,853,504	$ (79,933)	(0.89)%	$ 9,313,307	$ 139,231	$ 9,452,538	$ 275,781	$ 136,550	$ 56,618	$ 9,509,155	0.60%	$ 56,618	$ -
4	Large General Primary	9P	5	15,058,811	$ 643,029	$ 384,065	$ 1,027,094	$ 374,262	$ 1,017,291	$ (9,803)	(0.95)%	$ 1,070,491	$ 17,195	$ 1,087,685	$ 34,064	$ 16,870	$ 7,067	$ 1,094,752	0.65%	$ 7,067	$ -
5	Large General Transmission	9T	1	3,199,934	$ 117,393	$ 79,614	$ 197,007	$ 77,603	$ 194,997	$ (2,010)	(1.02)%	$ 205,273	$ 3,564	$ 208,837	$ 7,063	$ 3,499	$ 1,488	$ 210,326	0.71%	$ 1,488	$ -
6	Dusk to Dawn Lighting	15	0	432,196	$ 94,473	$ 11,398	$ 105,871	$ 11,110	$ 105,583	$ (288)	(0.27)%	$ 110,554	$ 510	$ 111,064	$ 1,011	$ 501	$ 213	$ 111,277	0.19%	$ 213	$ -
7	Large Power Primary	19P	6	168,569,794	$ 5,789,917	$ 4,299,191	$ 10,089,108	$ 4,188,900	$ 9,978,817	$ (110,291)	(1.09)%	$ 10,511,516	$ 192,474	$ 10,703,990	$ 381,262	$ 188,788	$ 78,497	$ 10,782,487	0.73%	$ 78,497	$ -
8	Large Power Transmission	19T	1	107,800,796	$ 3,769,063	$ 2,450,459	$ 6,219,521	$ 2,610,221	$ 6,379,284	$ 159,763	2.57%	$ 6,479,190	$ 119,955	$ 6,599,145	$ 237,575	$ 117,620	$ 277,383	$ 6,876,528	4.20%	$ 264,626	$ 12,757
9	Agricultural Irrigation Service	24	2,049	65,567,958	$ 4,563,299	$ 1,728,016	$ 6,291,316	$ 1,685,433	$ 6,248,732	$ (42,584)	(0.68)%	$ 6,562,133	$ 77,363	$ 6,639,496	$ 153,403	$ 76,040	$ 33,457	$ 6,672,952	0.50%	$ 33,457	$ -
10	Unmetered General Service	40	2	5,388	$ 189	$ 142	$ 331	$ 138	$ 328	$ (4)	(1.08)%	$ 345	$ 6	$ 352	$ 13	$ 6	$ 3	$ 354	0.76%	$ 3	$ -
11	Street Lighting	41	26	882,636	$ 121,563	$ 23,277	$ 144,840	$ 22,689	$ 144,252	$ (588)	(0.41)%	$ 151,192	$ 1,042	$ 152,234	$ 2,065	$ 1,023	$ 435	$ 152,670	0.29%	$ 435	$ -
12	Traffic Control Lighting	42	8	22,796	$ 1,635	$ 558	$ 2,193	$ 586	$ 2,221	$ 28	1.28%	$ 2,287	$ 27	$ 2,314	$ 53	$ 26	$ 54	$ 2,368	2.35%	$ 54	$ -
13	Total Uniform Tariffs		19,182	684,994,949	$ 34,488,007	$ 17,502,504	$ 51,990,511	$ 17,279,857	$ 51,767,864	$ (222,647)	(0.43)%	$ 54,254,768	$ 793,835	$ 55,048,602	$ 1,572,765	$ 778,931	$ 556,284	$ 55,604,886	1.01%	$ 543,526	$ 12,757
14	Total Oregon Retail Sales		19,182	684,994,949	$ 34,488,007	$ 17,502,504	$ 51,990,511	$ 17,279,857	$ 51,767,864	$ (222,647)	(0.43)%	$ 54,254,768	$ 793,835	$ 55,048,602	$ 1,572,765	$ 778,931	$ 556,284	$ 55,604,886	1.01%		

(1) Updated June 2019-May 2020 Test Year

Idaho Power Company
Revenue Spread Exhibit for 2020 APCU
Stipulated Revenue Spread

Line No.		
1	4.01% Increase Cap - Revenue Requirement Shortfall	$ 12,757

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
2	**April 2020 - March 2021 Generation Level Normalized Sales (kWh)**	**625,460,311**	203,714,779	21,359,651	129,187,704	15,957,170	3,308,733	473,684	178,599,571		71,860,761	5,904	967,370	24,984
3	**Class Share of April 2020 - March 2021 Generation Level Normalized Sales (kWh)**	**100%**	32.57%	3.42%	20.65%	2.55%	0.53%	0.08%	28.55%		11.49%	0.00%	0.15%	0.00%
4	**2020 APCU Class Allocated Revenue Requirement Shortfall**	**$ 12,757**	$ 4,155	$ 436	$ 2,635	$ 325	$ 67	$ 10	$ 3,643		$ 1,466	$ 0	$ 20	$ 0.5
5	**June 2020 - May 2021 Loss-Adjusted Normalized Sales (kWh)**	**577,194,153**	185,871,153	19,517,431	118,066,056	15,058,811	3,199,934	432,196	168,569,794		65,567,958	5,388	882,636	22,796
6	**2020 APCU Revenue Requirement Shortall Rates ($/kWh)**	**0.00002**	**0.00002**	**0.00002**	**0.00002**	**0.00002**	**0.00002**	**0.00002**	**0.00002**		**0.00002**	**0.00002**	**0.00002**	**0.00002**

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2020

Summary of Revenue Impact
Current Base Revenue to Proposed Base Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	2020 October Update Proposed Base NPSE Revenue	Total Proposed Base Revenue	2020 October Update Proposed Adjustments to Base Revenue	2020 October Update Base Revenue Percent Change	1st Pass Adjustment to 2020 October Update Proposed Base NPSE Revenue	1st Pass 2020 October Update Proposed Adjustments to Base Revenue	1st Pass 2020 October Update Base Revenue Percent Change	1st Pass 2020 October Update Proposed Base NPSE Revenue	Revised APCU Rates for 2020 October Update ($/kWh)
	Uniform Tariff Rates:															
1	Residential Service	1	13,474	185,871,153	$ 12,071,304	$ 4,901,740	$ 16,973,044	$ 4,777,956	$ 16,849,259	$ (123,784)	(0.73)%	$ 4,155	$ (119,629)	(0.70)%	$ 4,782,111	0.025728
2	Small General Service	7	2,672	19,517,431	$ 1,492,625	$ 514,125	$ 2,006,749	$ 500,972	$ 1,993,597	$ (13,152)	(0.66)%	$ 436	$ (12,717)	(0.63)%	$ 501,408	0.025690
3	Large General Secondary	9S	938	118,066,056	$ 5,823,517	$ 3,109,920	$ 8,933,436	$ 3,029,987	$ 8,853,504	$ (79,933)	(0.89)%	$ 2,635	$ (77,298)	(0.87)%	$ 3,032,622	0.025686
4	Large General Primary	9P	5	15,058,811	$ 643,029	$ 384,065	$ 1,027,094	$ 374,262	$ 1,017,291	$ (9,803)	(0.95)%	$ 325	$ (9,478)	(0.92)%	$ 374,587	0.024875
5	Large General Transmission	9T	1	3,199,934	$ 117,393	$ 79,614	$ 197,007	$ 77,603	$ 194,997	$ (2,010)	(1.02)%	$ 67	$ (1,943)	(0.99)%	$ 77,671	0.024273
6	Dusk to Dawn Lighting	15	0	432,196	$ 94,473	$ 11,398	$ 105,871	$ 11,110	$ 105,583	$ (288)	(0.27)%	$ 10	$ (278)	(0.26)%	$ 11,120	0.025728
7	Large Power Primary	19P	6	168,569,794	$ 5,789,917	$ 4,299,191	$ 10,089,108	$ 4,188,900	$ 9,978,817	$ (110,291)	(1.09)%	$ 3,643	$ (106,648)	(1.06)%	$ 4,192,543	0.024871
8	Large Power Transmission	19T	1	107,800,796	$ 3,769,063	$ 2,450,459	$ 6,219,521	$ 2,610,221	$ 6,379,284	$ 159,763	2.57%	$ -	$ 147,005	2.36%	$ 2,597,464	0.024095
9	Agricultural Irrigation Service	24	2,049	65,567,958	$ 4,563,299	$ 1,728,016	$ 6,291,316	$ 1,685,433	$ 6,248,732	$ (42,584)	(0.68)%	$ 1,466	$ (41,118)	(0.65)%	$ 1,686,898	0.025727
10	Unmetered General Service	40	2	5,388	$ 189	$ 142	$ 331	$ 138	$ 328	$ (4)	(1.08)%	$ 0	$ (3)	(1.05)%	$ 139	0.025723
11	Street Lighting	41	26	882,636	$ 121,563	$ 23,277	$ 144,840	$ 22,689	$ 144,252	$ (588)	(0.41)%	$ 20	$ (568)	(0.39)%	$ 22,709	0.025728
12	Traffic Control Lighting	42	8	22,796	$ 1,635	$ 558	$ 2,193	$ 586	$ 2,221	$ 28	1.28%	$ 1	$ 28	1.28%	$ 586	0.025705
13	Total Uniform Tariffs		19,182	684,994,949	$ 34,488,007	$ 17,502,504	$ 51,990,511	$ 17,279,857	$ 51,767,864	$ (222,647)	(0.43)%	$ 12,757	$ (222,647)	(0.43)%	$ 17,279,856	
14	Total Oregon Retail Sales		19,182	684,994,949	$ 34,488,007	$ 17,502,504	$ 51,990,511	$ 17,279,857	$ 51,767,864	$ (222,647)	(0.43)%	$ 12,757	$ (222,647)	(0.43)%	$ 17,279,856	

(1) Updated June 2019-May 2020 Test Year

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2020

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 w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	2020 March Forecast Proposed Revenue	2020 March Forecast Proposed Adjustments to Billed Revenue	2020 October Update Proposed Adjustments to Base Revenue	2020 Composite APCU Revenue Adjustment	Proposed Total Billed Revenue	2020 Composite APCU Percent Change
	Uniform Tariff Rates:												
1	Residential Service	1	13,474	185,871,153	$ 17,755,085	$ 219,450	$ 17,974,536	$ 434,876	$ 215,426	$ (119,629)	$ 95,797	$ 18,070,333	0.53%
2	Small General Service	7	2,672	19,517,431	$ 2,093,394	$ 23,017	$ 2,116,411	$ 45,597	$ 22,580	$ (12,717)	$ 9,863	$ 2,126,274	0.47%
3	Large General Secondary	9S	938	118,066,056	$ 9,313,307	$ 139,231	$ 9,452,538	$ 275,781	$ 136,550	$ (77,298)	$ 59,253	$ 9,511,790	0.63%
4	Large General Primary	9P	5	15,058,811	$ 1,070,491	$ 17,195	$ 1,087,685	$ 34,064	$ 16,870	$ (9,478)	$ 7,392	$ 1,095,077	0.68%
5	Large General Transmission	9T	1	3,199,934	$ 205,273	$ 3,564	$ 208,837	$ 7,063	$ 3,499	$ (1,943)	$ 1,556	$ 210,393	0.75%
6	Dusk to Dawn Lighting	15	0	432,196	$ 110,554	$ 510	$ 111,064	$ 1,011	$ 501	$ (278)	$ 223	$ 111,287	0.20%
7	Large Power Primary	19P	6	168,569,794	$ 10,511,516	$ 192,474	$ 10,703,990	$ 381,262	$ 188,788	$ (106,648)	$ 82,140	$ 10,786,130	0.77%
8	Large Power Transmission	19T	1	107,800,796	$ 6,479,190	$ 119,955	$ 6,599,145	$ 237,575	$ 117,620	$ 147,005	$ 264,626	$ 6,863,771	4.01%
9	Agricultural Irrigation Service	24	2,049	65,567,958	$ 6,562,133	$ 77,363	$ 6,639,496	$ 153,403	$ 76,040	$ (41,118)	$ 34,922	$ 6,674,418	0.53%
10	Unmetered General Service	40	2	5,388	$ 345	$ 6	$ 352	$ 13	$ 6	$ (3)	$ 3	$ 354	0.79%
11	Street Lighting	41	26	882,636	$ 151,192	$ 1,042	$ 152,234	$ 2,065	$ 1,023	$ (568)	$ 455	$ 152,689	0.30%
12	Traffic Control Lighting	42	8	22,796	$ 2,287	$ 27	$ 2,314	$ 53	$ 26	$ 28	$ 54	$ 2,368	2.35%
13	Total Uniform Tariffs		19,182	684,994,949	$ 54,254,768	$ 793,835	$ 55,048,602	$ 1,572,765	$ 778,931	$ (222,647)	$ 556,283	$ 55,604,886	1.01%
14	Total Oregon Retail Sales		19,182	684,994,949	$ 54,254,768	$ 793,835	$ 55,048,602	$ 1,572,765	$ 778,931	$ (222,647)	$ 556,283	$ 55,604,886	1.01%

(1) Updated June 2019-May 2020 Test Year