BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 301

In the Matter of: IDAHO POWER COMPANY 2016 ANNUAL POWER COST UPDATE	**JOINT EXPLANATORY BRIEF**

This brief explains and supports the Stipulation filed in this proceeding on May 11, 2016, among Idaho Power Company ("Idaho Power" or "Company"), the Citizens' Utility Board of Oregon ("CUB"), and Staff of the Public Utility Commission of Oregon ("Staff") (together, the "Stipulating Parties"). This Stipulation resolves all issues raised by the Stipulating Parties related to Idaho Power's 2016 Annual Power Cost Update ("APCU").

I. BACKGROUND

A. Idaho Power's APCU and Power Cost Adjustment Mechanism.

In Order No. 08-238 the Commission approved an automatic adjustment clause that allows Idaho Power to annually update its net power supply expense included in rates.[1] This automatic adjustment clause is referred to as the APCU and has two components—an "October Update" and a "March Forecast." The October Update contains the Company's forecasted net power supply expense reflected on a normalized per-unit basis for an April through March test period. The March Forecast contains the Company's net power supply expense based upon updated actual forecasted conditions. The mechanism allows for the rates from the October Update and March Forecast to become effective on June 1 of each year.

Pursuant to Order No. 10-191, the Company allocates the APCU revenue requirement to individual customer classes on the basis of the total generation-related revenue requirement

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

approved in the Company's last general rate case, instead of the equal cents per kilowatt-hout approved in Order No. 08-238.[2] Order No. 10-191 also directs the Company to adjust its base rates to reflect changes in revenue requirement related to the October Update, while the rates resulting from the March Forecast are listed on Schedule 55.

B. The 2016 October Update.

On October 23, 2015, Idaho Power filed testimony and exhibits for the 2016 October Update component of the APCU ("2016 October Update").[3] Pursuant to Order No. 08-238 the 2016 October Update updated the following variables: (1) fuel prices and transportation costs, (2) Public Utility Regulatory Policies Act of 1978 ("PURPA") expense, (3) normalized load and normalized sales, (4) contracts for wholesale power and power purchases and sales, (5) forward price curve, (6) heat rates, (7) planned outages and forced outage rates, and (8) the Oregon state allocation factor.[4] As part of the fuel expense update, the Company made changes to its treatment of Oil, Handling and Administrative and General ("OHAG") expenses at its coal-fired generation units, removing them from the AURORA model and treating them as fixed rather than variable costs.[5] Idaho Power made this change to better align the dispatch of the coal-fired generation units with the actual operational decisions that result in the dispatch of those plants and to produce a more accurate forecast of net power supply expenses to be included for recovery in the APCU.[6]

The test period for the 2016 October Update was April 2016 through March 2017 and included updates to the above referenced variables for all Company owned resources and

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

[3] *See* Idaho Power/100-108.

[4] Idaho Power/100, Noe/5 and 10.

[5] Idaho Power/100, Noe/7.

[6] Idaho Power/100, Noe/7-8.

updated sales and load forecasts.[7] The 2016 October Update specifically accounted for changes in natural gas and coal prices, and generation and expenses related to contracts entered into pursuant to PURPA.[8]

The filed 2016 October Update resulted in a cost per unit of $24.08 per megawatt-hour ("MWh"),[9] representing an increase of $0.64 per MWh over last year's October Update.[10] The 2016 October Update also included the Company's proposed method of allocation, which was consistent with the revenue spread methodology approved by the Commission in Order No. 10-191.[11]

On November 20, 2015, Administrative Law Judge ("ALJ") Allan Arlow held a prehearing conference at which the parties to UE 301 agreed upon a procedural schedule that would allow the Public Utility Commission of Oregon ("Commission") to issue an order on Idaho Power's 2016 APCU prior to June 1, 2016.[12] On October 27, 2015, CUB filed its Notice of Intervention.

Staff and CUB served discovery on Idaho Power and conducted a thorough investigation of the 2016 October Update. On February 12, 2016, Staff filed Opening Testimony and raised concerns related to the Company's change to its modeling of OHAG expenses, and charges recorded in Federal Energy Regulatory Commission ("FERC") account 501.[13] CUB did not file Opening Testimony.[14]

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[7] Idaho Power/100, Noe/6 and 10.

[8] Idaho Power/100, Noe/9-10 and 15-16.

[9] Idaho Power/100, Noe/13.

[10] Idaho Power/100, Noe/13.

[11] Idaho Power/100, Noe/16-17; Idaho Power/107.

[12] *Re Idaho Power Company's 2016 Annual Power Cost Update*, Docket UE 301, Prehearing Conference Memorandum at 1 (Nov. 20, 2015).

[13] Staff/100, Gibbens/4-5.

[14] *See Re Idaho Power Company's 2016 Annual Power Cost Update*, Docket UE 301, CUB's Letter (Feb. 12, 2016).

Idaho Power filed Reply Testimony on March 17, 2016, in which the Company responded to the concerns raised by Staff regarding the treatment of OHAG expense.[15] Specifically, Idaho Power explained that including the OHAG expenses as fixed costs, rather than variable costs, more accurately reflects the Company's dispatch of resources.[16]

C. The 2016 March Forecast.

On March 25, 2016, Idaho Power filed the 2016 March Forecast component of the APCU ("2016 March Forecast"). The 2016 March Forecast consisted of testimony describing the Company's estimate of the expected net power supply expense for the upcoming water year—April 2016 through March 2017.[17] Order No. 08-238 calls for the March Forecast to update the following variables: fuel prices, transportation costs, wheeling expenses, planned and forced outages, heat rates, forecast of normalized sales and loads updated for significant changes since the October Update, forecast hydro generation, wholesale power purchase and sale contracts, forward price curve, PURPA expenses, and the Oregon state allocation factor.[18] For the 2016 March Forecast, the variables that had changed since the October Update were: (1) fuel prices, (2) planned outage schedule, (3) forced outage rates, (4) normalized sales and loads, (5) forecast of hydro generation and current reservoir levels from stream flow conditions using the most recent water supply forecast from the Northwest River Forecast Center ("NRFC"), (6) known power purchases and surplus sales made in compliance with the Company's Energy Risk Management Policy, (7) forward price curve, and (8) PURPA contract expenses.[19]

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[15] *See* Idaho Power/200.

[16] *See* Idaho Power/200, Noe/1-3.

[17] Idaho Power/300-305.

[18] Idaho Power/300, Noe/3.

[19] Idaho Power/300, Noe/3-4.

The fuel prices were updated to reflect changes in forecast natural gas and coal costs.[20] The increase in the per-unit cost of the generation for the Jim Bridger and Valmy power plants was attributed to higher operating costs spread over lower production volumes.[21] OHAG expenses were removed from the AURORA model and included as a fixed-cost input consistent with the October update.[22] Forecast natural gas prices decreased as a result of lower demand and higher gas supply nationally.[23]

Idaho Power's forecast for normalized load decreased. This was due to a revised load forecast from one of the Company's large industrial customers that occurred between the October and March filings.[24]

The Company updated the hydro forecast.[25] Expected streamflows into Brownlee Reservoir were 24 percent higher than last year's levels, but remained below the 30-year average.[26] Hydro generation was greater than last year's modeled generation, but the increase was not more substantial because of the decreased flows coming from the upper Snake Basin.[27]

The 2016 March Forecast also included increased PURPA expenses. Updated contract values drove the increase in expense even though there was a slight decrease in total generation compared to the forecast prepared for the October Update.[28]

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[20] Idaho Power/300, Noe/4-6.

[21] Idaho Power/300, Noe/4-5.

[22] Idaho Power/300, Noe/4.

[23] Idaho Power/300, Noe/5.

[24] Idaho Power/300, Noe 6-7.

[25] Idaho Power/300, Noe/7-8.

[26] Idaho Power/300, Noe/7.

[27] Idaho Power/300, Noe/7-8.

[28] Idaho Power/300, Noe/6.

The Company calculated a cost per unit for the 2016 March Forecast of $25.56 per MWh, which is $0.56 per MWh more than last year's per unit cost of $25.00 per MWh.[29] A high level analysis of the increase suggests that it is driven by increased amounts of PURPA generation on the Company's system compared to last year's March Forecast.[30] Combining the 2016 October Update and 2016 March Forecast resulted in an overall proposed revenue increase of approximately 0.71 percent, or $0.4 million.[31]

The 2016 March Forecast also included the Company's proposed rate spread used to spread the revenue requirement to the various customer classes. The Company's proposed allocation conformed to the methodology approved by the Commission in Order No. 10-191.[32]

Again, Staff and CUB issued discovery, conducted a thorough investigation, and filed testimony.[33] Staff reviewed every updated input used in the March Forecast and found no errors associated with the calculations used in the APCU.[34] Additionally, Staff recommended that stakeholders work together to design and test a cost forecasting model to address its previously identified concerns regarding the modeling of OHAG expenses.[35] CUB recommended that the Commission deny the Company's proposed modeling changes, and that the Company should continue to work with the parties to address the issue of accurately forecasting costs. CUB also noted that at the time its rebuttal testimony was filed it still had several data requests outstanding and was continuing to work with parties to understand all related issues.[36]

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[29] Idaho Power/300, Noe/9-10.

[30] Idaho Power/300, Noe/11.

[31] Idaho Power/300, Noe/1.

[32] Idaho Power/300, Noe/12-13; Idaho/304.

[33] *See* Staff/200; CUB/100-103.

[34] Staff/200, Gibbens/3

[35] Staff/200, Gibbens/4-10.

[36] CUB/100, McGovern/18.

Settlement conferences and workshops were held on January 20, February 18, and April 5, 2016. Through these discussions, parties addressed the modeling of OHAG expenses, and made progress toward developing a methodology that parties believe is a reasonable reflection of expenses appropriate for recovery through the APCU. More specifically, parties discussed the nature of OHAG expenses, and the fact that most of these expenses vary with overall production at each coal-fired generation facility. However, per the terms of the operating agreements at each coal plant, the Company is required to pay an amount of OHAG expenses proportional to its ownership share regardless of its level of dispatch.

To address the unique nature of OHAG expenses, through settlement discussions the idea of a hybrid model was developed. The intent of the hybrid model is to separately identify variable costs associated with Idaho Power's dispatch of each plant and Idaho Power's share of OHAG expenses incurred due to the dispatch of each plant by the Company's ownership partners. The general concept of the hybrid approach is to only include the portion of OHAG expenses associated with Idaho Power's dispatch in the AURORA model, while separately accounting for Idaho Power's fixed percentage of OHAG expenses resulting from dispatch by the Company's ownership partners.

Ultimately the Stipulating Parties resolved all the issues in this case through these discussions, developing an agreed-upon adjustment to the Company's filed request in the current proceeding, as well as plans for further discussions of the OHAG modeling issue following the Company's 2017 APCU filing as detailed below. Thereafter Staff moved to suspend the schedule and ALJ Arlow granted the motion.[37]

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[37] *Re Idaho Power Company's 2016 Annual Power Cost Update*, Docket UE 301, Ruling (Apr. 21, 2016).

II. DISCUSSION

A. Terms of the Stipulation.

1. The Stipulating Parties agree to reduce Idaho Power's requested revenue requirement increase of $393,076 by $151,411, representing a compromise between the Stipulating Parties related to the treatment of modeled OHAG expenses at the Company's coal-fired generation units.[38] The calculation of the resulting stipulated revenue requirement change is detailed in Exhibit Nos. 1 through 5 attached to the Stipulation.

2. The Stipulating Parties agree that Idaho Power's 2017 APCU filing, in response to the concerns raised by parties, will model OHAG using the hybrid methodology that includes in the AURORA model a per-unit cost intended to reflect the amount of OHAG expense driven by Idaho Power's dispatch of each plant.[39]

3. The Stipulating Parties agree that after the initial 2017 APCU filing, the Stipulating Parties will hold workshops to discuss the hybrid model filed by the Company and the treatment of expenses related to the Company's proportionate share of OHAG resulting from its ownership partners' dispatch at each plant.[40]

4. The Stipulating Parties agree that the Company's allocation methodology conforms to that adopted by the Commission in Order No. 10-191.[41]

5. The Stipulating Parties agree that rates agreed to by the terms of this Stipulation should be made effective on June 1, 2016, as permitted by the APCU mechanism.[42]

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[38] Stipulation ¶ 21.

[39] Stipulation ¶ 22.

[40] Stipulation ¶ 23.

[41] Stipulation ¶ 24.

[42] Stipulation ¶ 25.

B. The Stipulation Will Result in Just and Reasonable Rates.

The Commission will adopt a stipulation if it is supported by competent evidence in the record, appropriately resolves the issues in a case, and results in just and reasonable rates.[43] When evaluating the rates, the Commission examines "the reasonableness of the overall rates."[44] Here, the Stipulation satisfies these standards.

First, the Stipulation is supported by the record, which includes the Company's testimony and exhibits describing the detailed calculations supporting both the 2016 October Update and 2016 March Forecast.[45] Staff and CUB conducted a thorough investigation of the Company's testimony and exhibits, and served numerous data requests. As a result of their investigation, Staff filed testimony in response to the 2016 October Update[46] and the 2016 March Forecast,[47] and CUB filed testimony in response to the 2016 March Forecast.[48] Staff and CUB raised concerns regarding certain aspects of Idaho Power's filing. These issues were addressed at settlement meetings and workshops. After negotiations, the Stipulating Parties reached agreement on all unresolved issues as detailed above. The parties agree that Idaho Power's filing followed the applicable rules and orders. The parties agree to a reduction to the revenue requirement, an OHAG modeling change, and to participate in workshops to address OHAG

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[43] *See Re PacifiCorp's 2010 Transition Adjustment Mechanism*, Docket UE 207, Order No. 09-432 at 6 (Oct. 30, 2009) ("The Commission concludes that the Stipulation is an appropriate resolution of all primary issues in this docket."); *See Re PacifiCorp Request for a General Rate Revision*, Docket UE 210, Order No. 10-022 at 6 (Jan. 26, 2010) ("When considering a stipulation, we have the statutory duty to make an independent judgment as to whether any given settlement constitutes a reasonable resolution of the issues."); *See Re PacifiCorp Request for a General Rate*, Docket UE 217, Order No. 10-473 at 7 (Dec. 14, 2010) ("We have reviewed the Stipulation, and find that it will result in rates that are fair, just, and reasonable.").

[44] *Re Application of Portland General Electric Co. for an Investigation into Least Cost Plant Retirement*, Docket DR 10 et al., Order No. 08-487 at 7-8 (Sept. 30, 2008).

[45] Idaho Power/100-108; Idaho Power/200; Idaho Power/300-305.

modeling issues going forward.[49] The Stipulating Parties agree that the testimony filed by Idaho Power, Staff, and CUB is sufficient to support a finding that the Stipulation is reasonable and should be adopted.

Second, the Stipulating Parties agree that the revenue requirement, as reduced by the Stipulation, results in a cost per-unit rate that is consistent with the methodology approved by the Commission in Order No. 08-238.[50] The Stipulating Parties also agree that the Company's proposed rate spread conforms to the methodology approved by the Commission in Order No. 10-191.[51] Because the Company's filed case, as modified by the Stipulation, reflects correct calculations that conform to Commission precedent, the resulting rates are just and reasonable and fall within the "range of reasonableness" for resolution of these issues.[52]

III. CONCLUSION

For all of the above reasons, the Stipulating Parties request that the Commission approve the Stipulation and the resulting rates.

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[49] Stipulation ¶¶ 21-23.

[50] Stipulation ¶ 26.

[51] Stipulation ¶ 24.

[52] *See Re US West*, Docket UM 773, Order No. 96-284 at 31 (Nov. 1, 1999).

DATED: May 11, 2016.

Respectfully submitted,

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