ORDER NO. 16 206

ENTERED MAY 31 2016

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 301

In the Matter of IDAHO POWER COMPANY, 2015 Annual Power Cost Update.	ORDER

DISPOSITION: STIPULATION ADOPTED; ANNUAL POWER COST UPDATE APPROVED

In this order, we adopt the stipulation of the parties and approve Idaho Power Company's Annual Power Cost Update (APCU). The APCU updates the company's net power supply expenses and results in new rates to go into effect June 1, 2016.

I. INTRODUCTION

In Order No. 08-238, we approved an automatic adjustment clause for Idaho Power that allows the company to annually update its net power supply expense included in rates. The APCU is comprised of 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 and unit basis for an April through March test period. The March Forecast contains the company's net power supply expenses based on updated actual forecast conditions. The APCU mechanism allows for the rates from the October Update and March Forecast to become effective on June 1 of each year.

II. PROCEDURAL HISTORY

On October 23, 2015, Idaho Power filed testimony and exhibits for its 2016 APCU, including the October Update which estimated what the normal power supply expenses would be for the 12-month test year, April 2016 through March 2017. The company subsequently filed the March Forecast on March 25, 2016.

Following discovery, the submission of reply testimony to the March Forecast and settlement discussion, the company, the Citizens' Utility Board of Oregon (CUB) and the Commission Staff filed a stipulation, attached as Appendix A, settling all of the outstanding issues between the parties. The stipulation was supported by a joint explanatory brief.

III. THE 2016 APCU

Idaho Power's 2016 October Update projects a cost per unit of $24.08 per megawatt-hour (MWh), an increase of $0.64 per MWh over the previous year's October Update.[1] The update addressed the following variables: fueling prices, transportation costs, heat rates, planned and forced outage rates, forecast of normalized load and normalized sales, contracts for wholesale power and power purchases and sales, forward price curve, PURPA contract expense, and the Oregon state allocation factor. In the 2015 October Update, Idaho Power also included a proposed allocation method, which the company represented as being consistent with the revenue spread methodology we approved in Order No. 10-191.[2]

Idaho Power's 2016 March Forecast calculates a cost per unit of $25.56 per MWh, $0.56 per MWh more than the previous year's $25.00 per MWh per unit cost. In the forecast, Idaho Power updated its forecast for the April 2016 through March 2017 water year and addressed the following:

1. Fuel prices were updated to reflect changes in forecast natural gas and coal costs. 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.[3] Oil, Handling, and Administrative and General (OHAG) expenses were removed from the AURORA model and included as a fixed-cost input consistent with the October Update. Forecast natural gas prices decreased as a result of lower demand and higher gas supply nationally.[4]

2. The forecast for normalized load decreased due to a revised load forecast by a large industrial customer that occurred between the October and March filings.[5]

3. The updated hydro forecast reflected a 24 percent expected increase over last year's streamflows into Brownlee Reservoir, although still remaining below the 30-year average.[6] Although hydro generation was greater than the previous year's modeled generation, the increase was not more substantial because of the decreased flows coming from the upper Snake Basin.[7]

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[1] Idaho Power/100, Noe/13.
[2] *Id.* at/16-17; Idaho Power/107, Noe.
[3] Idaho Power/300, Noe/ 4-6.
[4] *Id.* at 4-5.
[5] *Id.* at 6-7.
[6] *Id.* at 7.
[7] *Id.* at 7-8.

4. PURPA expenses increased due to updated contract values, despite a slight decrease in total generation compared to the forecast prepared for the October Update.[8]

Combining the 2015 October Update and 2016 March Forecast results in an overall proposed combined rate increase of approximately 0.71 percent or $0.4 million.[9] Idaho Power proposes to spread the revenue requirement changes among the various customer classes in conformance with Order No. 10-191.[10]

Following filing of testimony and settlement discussions, the parties reached a settlement of all issues. On May 11, 2016, the parties filed a stipulation and joint explanatory brief.

IV. THE STIPULATION

The parties agree that we should adopt Idaho Power's 2016 APCU subject to certain changes in the current filing, and the adoption of conditions regarding the 2017 APCU filing. Specifically, the parties agree that:

1. Idaho Power's requested revenue requirement increase of $393,076 should be reduced by $151,411. This reduction represents a compromise between the stipulating parties related to the treatment of modeled OHAG expenses at the company's coal-fired generation units.[11]

2. Idaho Power's allocation methodology conforms to that adopted by the Commission in Order No. 10-191.[12]

3. The rates agreed to by the terms of the stipulation should be made effective on June 1, 2016, as permitted by the APCU mechanism.[13]

4. Idaho Power's 2017 APCU filing 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 the company's dispatch of each plant.[14]

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[8] *Id.* at 6.
[9] *Id.* at 1.
[10] *Id.*
[11] Stipulation at ¶ 23 and exhibits 1-5 thereto.
[12] *Id.* at ¶ 26.
[13] *Id.* at ¶ 27.
[14] *Id.* at ¶ 24.

5. After the initial 2017 APCU filing, the stipulating parties will hold workshops to discuss the hybrid model filed by Idaho Power and the treatment of expenses related to the company's proportionate share of OHAG resulting from its ownership partners' dispatch at each plant.[15]

V. DISCUSSION

We find that the stipulation is supported by competent evidence in the record, appropriately resolves the issues in the case, and results in just and reasonable rates.[16] Both Staff and CUB conducted a thorough investigation of the company's testimony and exhibits, served numerous data requests, participated in settlement conferences and filed responsive testimony. Staff and all parties entered into the stipulation that resolves all relevant issues in this proceeding and have each executed the joint explanatory brief. No person has filed an objection to the stipulation.

We have examined the stipulation, the joint explanatory brief, and the pertinent record in the case. We find that the stipulation is supported by the record, which includes the company's testimony and exhibits describing the detailed calculations supporting both the 2015 October Update and the 2016 March Forecast, Staff and CUB's testimony thereon and the stipulated modifications to the March 2016 Forecast. We therefore conclude that the resulting rates are just and reasonable for resolution of the issues in this docket. The stipulation should be adopted in its entirety.

VI. ORDER

IT IS ORDERED that:

1. The stipulation between Idaho Power Company, the Staff of the Public Utility Commission of Oregon, and the Citizens' Utility Board of Oregon, attached as Appendix A, is adopted.

2. Idaho Power must file revised rate schedules consistent with this order to be effective no earlier than June 1, 2016.

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[15] *Id.* at ¶ 25.

[16] *See, e.g., In the Matter of PacifiCorp, dba Pacific Power 2010 Transition Adjustment Mechanism,* Docket No. UE 207, Order No. 09-432 at 6 (Oct 30, 2009).

3. Idaho Power's 2017 Annual Power Cost Update filing shall conform to the terms of the stipulation.

Made, entered, and effective MAY 31 2016.

John Savage
Commissioner

Stephen M. Bloom
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 301

In the Matter of IDAHO POWER COMPANY 2016 ANNUAL POWER COST UPDATE	**STIPULATION**

This Stipulation resolves all issues among the parties to Idaho Power Company's ("Idaho Power" or "Company") 2016 Annual Power Cost Update ("APCU") filed pursuant to Order No. 08-238.[1] The APCU updates the Company's net power supply expense and results in new rates, which the mechanism permits to go into effect June 1, 2016.

PARTIES

1. The parties to this Stipulation are Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), and Idaho Power (together, the "Stipulating Parties").

BACKGROUND

2. Pursuant to Order No. 08-238, Idaho Power annually updates its net power supply expense included in rates through an automatic adjustment clause, the APCU. The APCU is comprised of 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. 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

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[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 previous equal cents per kilowatt-hour 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. The rates associated with the October Update and the March Forecast mechanisms are intended, under the mechanisms, to become effective on June 1 of each year.

3. 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, Idaho Power reviewed all the inputs and provided the changes in the 2016 October Update for 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]

4. 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]

5. 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]

6. 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]

7. 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]

8. On October 27, 2015, CUB filed its Notice of Intervention.

9. 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 found that Idaho Power's filing followed all of the applicable rules and orders.[13] Staff also raised concerns related to the Company's change to its modeling of OHAG expenses, and

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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/1.

charges recorded in Federal Energy Regulatory Commission ("FERC") account 501.[14] CUB did not file Opening Testimony.[15]

10. 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.[16] 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.[17]

11. On March 25, 2016, Idaho Power filed the 2016 March Forecast component of the APCU ("2016 March Forecast"). The 2016 March Forecast consisted of direct testimony describing the Company's estimate of the expected net power supply expense for the upcoming water year—April 2016 through March 2017.[18] 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.[19] Idaho Power reviewed all the variables for the March Forecast and the following variables changed since the 2016 October Update: (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

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

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

[16] *See* Idaho Power/200.

[17] *See* Idaho Power/200, Noe/1-2.

[18] Idaho Power/300-305.

[19] *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).

made in compliance with the Company's Energy Risk Management Policy, (7) forward price curve, and (8) PURPA contract expenses.[20]

12. The fuel prices were updated to reflect changes in forecast natural gas and coal costs.[21] 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.[22] OHAG expenses were removed from the AURORA model and included as a fixed-cost input consistent with the October Update.[23] Forecast natural gas prices decreased as a result of lower demand and higher gas supply nationally.[24]

13. Idaho Power's forecast for normalized load decreased due to a revised load forecast from one of the Company's large industrial customers that occurred between the October and March filings.[25]

14. The Company updated the hydro forecast.[26] Expected streamflows into Brownlee Reservoir were 24 percent higher than last year's levels, but remained below the 30-year average.[27] 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.[28]

15. 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.[29]

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[20] Idaho Power/300, Noe/3-4.
[21] Idaho Power/300, Noe/4-6.
[22] Idaho Power/300, Noe/4-5.
[23] Idaho Power/300, Noe/4.
[24] Idaho Power/300, Noe/5-6.
[25] Idaho Power/300, Noe 6-7.
[26] Idaho Power/300, Noe/7-8.
[27] Idaho Power/300, Noe/7.
[28] Idaho Power/300, Noe/7-8.
[29] Idaho Power/300, Noe/6.

16. 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.[30] 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.[31]

17. The overall proposed revenue impact of the combined October and March rates was an increase of approximately 0.71 percent, or $393,076.[32]

18. 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.[33]

19. Staff and CUB issued discovery, conducted a thorough investigation, and filed testimony addressing the March forecast.[34] Staff reviewed every updated input used in the March Forecast and found no errors associated with the calculations used in the APCU.[35] 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.[36] 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.[37]

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

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

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

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

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

[35] Staff/200, Gibbens/3

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

[37] CUB/100, McGovern/18.

20. 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.

21. 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.

22. 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.[38]

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

AGREEMENT

23. The Stipulating Parties agree to reduce Idaho Power's requested revenue requirement increase of $393,076 million 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. The calculation of the stipulated revenue requirement change is detailed in Exhibit Nos. 1 through 5 attached to this Stipulation.

24. 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].

25. 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]

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

27. 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.

28. The Stipulating Parties agree the result is in conformance with the methodology adopted by the Commission in Order No. 08-238.

29. The Stipulating Parties agree that the rate increase resulting from the Stipulation results in rates that are fair, just, and reasonable.

30. The Stipulating Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented.

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[39] Stipulation ¶ 22.

[40] Stipulation ¶ 23.

31. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and any appeal, (if necessary) provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein.

32. If this Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Stipulating Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

33. The Stipulating Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

34. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

35. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

36. This Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: [signature]

Date: 5/11/16

IDAHO POWER

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________

Date: ______________________

36. This Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: ______________________________

Date: ______________________________

IDAHO POWER

By: ______________________________

Date: May 11, 2016

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________________

Date: ______________________________

36. This Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: ____________________________

Date: ____________________________

IDAHO POWER

By: ____________________________

Date: ____________________________

CITIZENS' UTILITY BOARD OF OREGON

By: ____________________________

Date: 5/11/16

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2016 -- MARCH 31, 2017 (Multiple Gas Prices/87 Years of Hydro Conditions)
Repriced Using UE 195 Settlement Methodology - October Update
AVERAGE
with Variable Coal Handling Costs included in AURORA dispatch

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	898,731.9	951,673.5	924,401.1	702,807.2	481,418.0	564,226.8	545,378.2	459,707.6	681,241.4	761,062.3	840,101.3	861,316.5	8,662,066.1
Bridger													
Energy (MWh)	70,010.3	57,850.9	131,482.2	330,743.4	328,908.3	173,527.2	142,016.1	251,283.3	315,694.7	255,650.0	191,286.1	212,284.3	2,460,735.8
AURORA Modeled Expense ($ x 1000)	$ 2,022.3	$ 1,668.7	$ 3,740.0	$ 9,280.6	$ 9,225.9	$ 4,907.3	$ 4,053.0	$ 7,106.1	$ 8,818.0	$ 7,154.2	$ 5,345.2	$ 5,952.0	$ 69,273.3
AURORA Modeled Handling Expense ($ x 1000)	$ 41.3	$ 34.1	$ 77.6	$ 195.1	$ 194.1	$ 102.4	$ 83.8	$ 148.3	$ 186.3	$ 150.8	$ 112.9	$ 125.2	$ 1,451.8
AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 1,981.0	$ 1,634.6	$ 3,662.5	$ 9,085.5	$ 9,031.8	$ 4,804.9	$ 3,969.2	$ 6,957.8	$ 8,631.8	$ 7,003.3	$ 5,232.3	$ 5,826.8	$ 67,821.5
IPC Share of OHAG Expense ($ x 1000)	$ 294.9	$ 294.9	$ 294.9	$ 294.9	$ 294.9	$ 294.9	$ 294.9	$ 294.9	$ 294.9	$ 294.9	$ 294.9	$ 294.9	$ 3,538.4
Total Expense ($ x 1000)	$ 2,275.8	$ 1,929.5	$ 3,957.3	$ 9,380.3	$ 9,326.8	$ 5,099.8	$ 4,264.1	$ 7,252.7	$ 8,926.6	$ 7,298.2	$ 5,527.2	$ 6,121.6	$ 71,359.9
Boardman													
Energy (MWh)	5,198.0	4,320.9	16,801.0	33,757.3	34,620.8	26,845.9	23,486.8	28,664.7	32,681.7	22,387.7	17,165.0	18,579.1	264,528.8
AURORA Modeled Expense ($ x 1000)	$ 133.7	$ 113.1	$ 430.1	$ 845.7	$ 867.7	$ 678.8	$ 597.0	$ 723.0	$ 819.5	$ 624.4	$ 479.2	$ 519.0	$ 6,831.1
AURORA Modeled Handling Expense ($ x 1000)	$ 1.9	$ 1.6	$ 6.2	$ 12.5	$ 12.8	$ 9.9	$ 8.7	$ 10.6	$ 12.1	$ 8.3	$ 6.4	$ 6.9	$ 97.9
AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 131.8	$ 111.5	$ 423.9	$ 833.2	$ 854.9	$ 668.8	$ 588.3	$ 712.4	$ 807.4	$ 616.1	$ 472.8	$ 512.2	$ 6,733.2
IPC Share of OHAG Expense ($ x 1000)	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.4
Total Expense ($ x 1000)	$ 131.9	$ 111.5	$ 423.9	$ 833.2	$ 854.9	$ 668.9	$ 588.3	$ 712.4	$ 807.4	$ 616.1	$ 472.9	$ 512.2	$ 6,733.6
Valmy													
Energy (MWh)	2,332.9	3,462.2	8,086.0	39,285.7	33,127.2	17,543.2	14,109.2	20,746.1	35,498.5	16,959.5	15,331.2	6,971.2	213,452.8
AURORA Modeled Expense ($ x 1000)	$ 84.9	$ 126.6	$ 280.7	$ 1,313.1	$ 1,108.9	$ 590.2	$ 490.5	$ 716.2	$ 1,179.8	$ 584.0	$ 528.5	$ 249.5	$ 7,252.6
AURORA Modeled Handling Expense ($ x 1000)	$ 2.9	$ 4.4	$ 10.2	$ 49.5	$ 41.7	$ 22.1	$ 17.8	$ 26.1	$ 44.7	$ 21.4	$ 19.3	$ 8.8	$ 269.0
AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 81.9	$ 122.2	$ 270.5	$ 1,263.6	$ 1,067.1	$ 568.1	$ 472.7	$ 690.1	$ 1,134.9	$ 562.7	$ 509.2	$ 240.7	$ 6,983.6
IPC Share of OHAG Expense ($ x 1000)	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 1,466.0
Total Expense ($ x 1000)	$ 204.1	$ 244.4	$ 392.7	$ 1,385.8	$ 1,189.3	$ 690.2	$ 594.9	$ 812.2	$ 1,257.1	$ 684.8	$ 631.3	$ 362.9	$ 8,449.6
Langley Gulch													
Energy (MWh)	164,339.3	163,637.8	183,347.0	198,360.1	198,511.5	192,260.8	195,933.9	169,671.2	169,916.1	160,987.5	150,126.8	168,969.4	2,116,061.5
Expense ($ x 1000)	$ 2,890.5	$ 2,754.1	$ 3,116.2	$ 3,372.3	$ 3,504.2	$ 3,365.0	$ 3,478.1	$ 3,681.6	$ 4,099.0	$ 3,822.1	$ 3,359.2	$ 3,700.7	$ 41,143.0
Danskin													
Energy (MWh)	2,039.9	1,805.2	14,944.4	71,339.9	63,200.6	37,197.9	26,168.6	10,692.5	5,148.9	1,580.4	2,521.4	835.7	237,469.2
Expense ($ x 1000)	$ 37.8	$ 35.9	$ 345.6	$ 1,868.5	$ 1,634.3	$ 910.4	$ 563.2	$ 251.6	$ 128.1	$ 39.8	$ 64.0	$ 19.9	$ 5,919.2
Bennett Mountain													
Energy (MWh)	248.1	102.9	4,885.1	43,071.3	32,813.4	15,078.0	10,541.5	4,527.5	1,665.4	183.7	266.9	32.6	113,240.3
Expense ($ x 1000)	$ 4.4	$ 2.1	$ 105.9	$ 1,093.9	$ 797.0	$ 338.9	$ 215.7	$ 99.7	$ 39.9	$ 4.3	$ 6.3	$ 0.8	$ 2,708.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 735.4	$ 759.4	$ 744.4	$ 778.0	$ 778.0	$ 753.4	$ 759.4	$ 735.4	$ 759.4	$ 759.4	$ 687.3	$ 759.4	$ 9,008.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	2,916.3	6,860.3	21,821.3	87,840.3	95,712.9	42,708.3	10,515.7	48,160.4	15,754.0	34,482.0	2,491.2	4,219.4	364,482.3
Elkhorn Wind Energy (MWh)	25,790.0	24,592.0	24,055.4	26,860.8	24,330.6	20,734.6	21,842.2	29,820.2	29,732.8	24,269.2	24,158.8	28,532.8	304,739.1
Neal Hot Springs Energy (MWh)	14,424.2	10,940.5	11,065.3	7,822.4	9,524.6	11,266.0	12,896.6	16,671.7	17,970.0	18,765.7	16,385.0	16,782.0	164,934.1
Raft River Geothermal Energy (MWh)	6,213.3	5,111.2	5,097.5	5,661.1	5,734.4	5,757.2	7,594.7	6,634.5	6,897.6	6,890.5	6,324.0	6,504.2	74,420.3
Total Energy Excl CSPP (MWh)	49,343.8	47,504.0	62,039.5	128,204.6	126,702.6	80,486.0	52,849.2	101,286.9	70,354.3	84,407.4	49,359.0	56,038.4	908,575.7
Market Expense ($ x 1000)	$ 71.7	$ 154.4	$ 469.6	$ 2,696.8	$ 2,994.7	$ 1,411.2	$ 332.6	$ 1,635.9	$ 578.2	$ 1,239.9	$ 86.0	$ 132.1	$ 11,803.1
Elkhorn Wind Expense ($ x 1000)	$ 1,115.4	$ 1,053.6	$ 1,415.7	$ 1,898.1	$ 1,718.0	$ 1,220.2	$ 1,285.4	$ 2,105.6	$ 2,099.4	$ 1,471.0	$ 1,464.3	$ 1,271.1	$ 18,127.7
Neal Hot Springs Expense ($ x 1000)	$ 1,155.2	$ 876.2	$ 1,209.1	$ 1,025.7	$ 1,301.3	$ 1,233.2	$ 1,409.2	$ 2,186.0	$ 2,358.2	$ 2,098.6	$ 1,832.3	$ 1,375.6	$ 18,058.7
Raft River Geothermal Expense ($ x 1000)	$ 289.1	$ 237.8	$ 322.7	$ 430.0	$ 435.6	$ 364.4	$ 480.7	$ 504.0	$ 523.9	$ 445.3	$ 408.7	$ 309.0	$ 4,751.3
Total Expense Excl CSPP ($ x 1000)	$ 2,631.4	$ 2,332.0	$ 3,417.0	$ 6,050.5	$ 6,449.6	$ 4,229.1	$ 3,508.0	$ 6,431.5	$ 5,557.8	$ 5,254.8	$ 3,791.3	$ 3,087.8	$ 52,740.8
Surplus Sales													
Energy (MWh)	388,307.6	287,920.7	221,457.5	39,030.6	28,828.0	50,759.0	180,808.3	57,360.7	148,519.2	138,670.3	314,313.3	396,607.9	2,235,582.1
Revenue Including Transmission Costs ($ x 1000)	$ 8,653.9	$ 5,874.3	$ 4,320.0	$ 1,086.4	$ 902.7	$ 1,520.6	$ 4,698.6	$ 1,767.0	$ 4,943.3	$ 4,521.9	$ 9,842.6	$ 11,259.4	$ 59,391.0
Transmission Costs ($ x 1000)	$ 388.3	$ 287.9	$ 221.5	$ 39.0	$ 28.8	$ 50.9	$ 163.8	$ 57.4	$ 148.5	$ 138.7	$ 314.3	$ 396.6	$ 2,235.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 8,265.6	$ 5,586.4	$ 4,098.6	$ 1,047.3	$ 873.9	$ 1,470.0	$ 4,534.8	$ 1,709.7	$ 4,794.7	$ 4,383.3	$ 9,528.3	$ 10,862.8	$ 57,155.4
Net Hedges													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Power Supply Expenses ($ x 1000)	$ 645.7	$ 2,582.5	$ 8,404.3	$ 23,715.2	$ 23,660.2	$ 14,585.6	$ 9,456.9	$ 18,297.5	$ 16,780.6	$ 14,098.2	$ 5,011.2	$ 3,702.5	$ 140,908.3
PURPA ($ x 1000)	$16,759.31	$18,807.64	$21,649.88	$23,505.36	$21,062.57	$18,736.52	$16,919.82	$15,975.03	$15,565.85	$12,045.69	$14,314.33	$13,551.38	$ 208,893.4
Total Net Power Supply Expenses ($ x 1000)	$ 17,405.0	$ 21,300.1	$ 30,054.2	$ 47,220.6	$ 44,722.8	$ 33,322.1	$ 26,376.7	$ 34,242.5	$ 32,346.4	$ 26,141.9	$ 19,325.5	$ 17,253.9	$ 349,801.676
Sales at Customer Level (In 000s MWH)	1,028.406	1,049.929	1,230.508	1,474.064	1,554.056	1,387.063	1,110.593	1,032.641	1,159.609	1,277.132	1,213.385	1,105.482	14,616.871
Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
Unit Cost / MWH (for PCAM)	$16.92	$20.37	$24.42	$32.03	$28.78	$24.02	$23.75	$33.16	$28.04	$20.47	$15.93	$15.61	$23.93
Prices Used in Purchased Power & Surplus Sales Above:													
Heavy Load													
Portion of Purchased Power considered HL Purchase	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	
Purchased Power HL Price	27.21	25.23	25.59	35.21	38.40	38.31	32.98	35.53	38.53	37.85	36.41	32.82	
Portion of Surplus Sales considered HL Surplus Sale:	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	
Surplus Sales HL Price	25.24	24.33	23.75	32.67	35.63	33.69	30.58	32.87	35.74	35.11	33.78	30.45	
Light Load													
Portion of Purchased Power considered LL Purchase:	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	
Purchased Power LL Price	19.88	15.82	14.20	22.59	27.59	27.17	28.23	31.16	33.42	32.57	31.16	28.58	
Portion of Surplus Sales considered LL Surplus Sale:	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	
Surplus Sales LL Price	17.32	13.79	12.38	19.70	24.06	23.69	25.49	27.17	29.15	28.40	27.17	24.93	

ORDER NO. 16 206

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2016 -- MARCH 31, 2017 (One Hydro Condition)
Repriced Using UE 195 Settlement Methodology - March Forecast
with Variable Coal Handling Costs Included in AURORA dispatch

Line No		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	789,980.9	921,428.8	790,376.7	607,454.9	437,657.4	517,995.6	484,929.1	373,156.8	450,648.7	700,537.8	836,632.4	886,675.1	7,797,474.2
	Bridger													
2	Energy (MWh)	-	-	3,710.1	266,182.4	278,869.0	75,787.3	107,333.7	236,509.6	314,979.3	187,393.5	33,950.3	10,205.8	1,514,920.2
	AURORA Modeled Expense ($ x 1000)	-	-	114.7	7,618.5	7,960.5	2,268.7	3,121.3	6,786.6	8,887.9	5,454.7	1,020.3	311.4	43,544.5
	AURORA Modeled Handling Expense ($ x 1000)	-	-	2.2	157.0	164.5	44.7	63.3	139.5	185.8	110.6	20.0	6.0	893.8
	AURORA Expense less Modeled Handling Expense ($ x 1000)	-	-	112.5	7,461.4	7,796.0	2,224.0	3,058.0	6,647.0	8,702.0	5,344.1	1,000.3	305.4	42,650.7
	IPC Share of OHAG Expense ($ x 1000)	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	294.9	3,538.4
3	Total Expense ($ x 1000)	$ 294.9	$ 294.9	$ 407.4	$ 7,756.3	$ 8,090.8	$ 2,518.9	$ 3,352.9	$ 6,941.9	$ 8,996.9	$ 5,639.0	$ 1,295.1	$ 600.2	$ 46,189.1
	Boardman													
4	Energy (MWh)	824.4	824.4	8,217.2	34,603.6	37,970.2	24,123.4	21,577.2	24,240.7	39,490.0	21,743.1	8,228.3	4,871.6	226,714.1
	AURORA Modeled Expense ($ x 1000)	25.3	25.3	217.3	858.7	940.7	610.8	553.5	616.0	974.0	601.0	245.7	152.9	5,821.3
	AURORA Modeled Handling Expense ($ x 1000)	0.3	0.3	3.0	12.8	14.0	8.9	8.0	9.0	14.6	8.0	3.0	1.8	83.9
	AURORA Expense less Modeled Handling Expense ($ x 1000)	25.0	25.0	214.2	845.9	926.7	601.8	545.6	607.0	959.4	592.9	242.7	151.1	5,737.4
	IPC Share of OHAG Expense ($ x 1000)	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	356.4
5	Total Expense ($ x 1000)	$ 54.7	$ 54.7	$ 243.9	$ 875.6	$ 956.4	$ 631.5	$ 575.3	$ 636.7	$ 989.1	$ 622.6	$ 272.4	$ 180.8	$ 6,093.8
	Valmy													
6	Energy (MWh)	-	-	-	-	-	-	-	-	13,677.0	-	-	-	13,677.0
	AURORA Modeled Expense ($ x 1000)	-	-	-	-	-	-	-	-	507.3	-	-	-	507.3
	AURORA Modeled Handling Expense ($ x 1000)	-	-	-	-	-	-	-	-	17.2	-	-	-	17.2
	AURORA Expense less Modeled Handling Expense ($ x 1000)	-	-	-	-	-	-	-	-	490.0	-	-	-	490.0
	IPC Share of OHAG Expense ($ x 1000)	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	1,466.0
7	Total Expense ($ x 1000)	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 122.2	$ 612.2	$ 122.2	$ 122.2	$ 122.2	$ 1,956.0
	Langley Gulch													
8	Energy (MWh)	183,192.5	190,046.4	191,988.5	198,344.9	198,638.5	192,228.6	191,850.1	163,382.4	189,339.0	174,118.6	121,742.4	152,328.5	2,167,198.4
9	Expense ($ x 1000)	$ 2,281.9	$ 2,133.4	$ 2,235.2	$ 2,732.3	$ 2,832.7	$ 2,764.7	$ 3,140.7	$ 3,812.5	$ 4,609.9	$ 4,026.5	$ 2,702.9	$ 3,273.9	$ 36,546.8
	Danskin													
10	Energy (MWh)	15,568.2	44,628.5	87,308.4	103,823.4	112,554.4	74,913.4	12,646.4	207.1	43.3	43.4	-	108.0	451,864.5
11	Expense ($ x 1000)	$ 326.1	$ 847.5	$ 1,748.6	$ 2,425.9	$ 2,714.2	$ 1,797.2	$ 342.3	$ 7.0	$ 1.7	$ 1.6	$ -	$ 3.8	$ 10,215.9
	Bennett Mountain													
12	Energy (MWh)	2,294.0	5,774.9	49,261.8	79,527.5	82,084.9	48,984.5	1,412.0	-	-	-	-	-	269,339.5
13	Expense ($ x 1000)	$ 48.9	$ 111.8	$ 988.8	$ 1,867.6	$ 1,990.6	$ 1,194.5	$ 38.8	$ -	$ -	$ -	$ -	$ -	$ 6,241.1
14	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 723.2	$ 746.8	$ 732.2	$ 765.4	$ 765.4	$ 741.2	$ 746.8	$ 723.2	$ 746.8	$ 748.8	$ 677.7	$ 748.8	$ 8,866.1
	Purchased Power (Excluding PURPA)													
15	Market Energy (MWh)	8,542.5	1,767.0	68,183.4	31,128.7	116,521.4	70,466.4	41,121.7	100,493.0	91,118.1	94,347.9	20,676.7	9,869.1	654,235.8
16	Elkhorn Wind Energy (MWh)	25,790.0	24,592.0	23,934.6	26,559.8	24,064.4	19,958.8	20,960.4	30,426.8	29,073.2	24,269.2	24,158.8	28,532.8	302,320.5
17	Neal Hot Springs Energy (MWh)	14,424.2	10,940.5	11,065.3	7,822.4	9,924.6	11,286.0	12,896.5	16,671.7	17,970.0	18,765.7	15,365.0	16,782.0	164,934.1
18	Raft River Geothermal Energy (MWh)	6,213.3	5,111.2	5,097.5	5,661.1	5,734.4	5,757.2	7,594.7	6,634.5	6,897.6	6,890.5	6,324.0	6,504.2	74,420.3
19	Total Energy Excl PURPA (MWh)	54,970.0	42,410.7	108,280.8	71,172.0	156,244.8	107,468.3	82,573.5	154,226.0	145,058.8	144,273.3	67,544.5	61,688.1	1,195,910.7
20	Market Expense ($ x 1000)	$ 70.7	$ 11.3	$ 614.8	$ 424.3	$ 2,387.4	$ 1,443.0	$ 841.7	$ 2,241.3	$ 2,313.5	$ 2,243.2	$ 500.9	$ 200.0	$ 13,292.1
21	Elkhorn Wind Expense ($ x 1000)	$ 1,115.4	$ 1,063.6	$ 1,408.5	$ 1,875.4	$ 1,699.2	$ 1,174.6	$ 1,233.5	$ 2,148.4	$ 2,052.9	$ 1,471.0	$ 1,464.3	$ 1,271.1	$ 17,977.9
22	Neal Hot Springs Expense ($ x 1000)	$ 1,155.2	$ 876.2	$ 1,209.1	$ 1,025.7	$ 1,301.3	$ 1,233.2	$ 1,409.2	$ 2,186.0	$ 2,356.2	$ 2,098.6	$ 1,832.3	$ 1,375.6	$ 18,058.7
23	Raft River Geothermal Expense ($ x 1000)	$ 289.1	$ 237.8	$ 322.7	$ 430.0	$ 435.6	$ 364.4	$ 480.7	$ 504.0	$ 523.9	$ 445.3	$ 408.7	$ 309.0	$ 4,751.3
24	Total Expense Excl CSPP ($ x 1000)	$ 2,630.5	$ 2,189.0	$ 3,555.1	$ 3,755.4	$ 5,823.5	$ 4,215.2	$ 3,965.1	$ 7,079.7	$ 7,246.5	$ 6,258.1	$ 4,206.2	$ 3,155.7	$ 54,080.0
	Surplus Sales													
25	Energy (MWh)	264,664.3	254,668.7	81,517.3	85,351.5	23,525.3	13,759.1	39,366.3	10,390.4	20,510.7	19,272.8	101,485.4	184,038.5	1,098,550.2
26	Revenue Including Transmission Costs ($ x 1000)	$ 2,691.4	$ 2,160.7	$ 830.8	$ 1,439.6	$ 520.9	$ 268.3	$ 741.0	$ 211.5	$ 532.3	$ 463.0	$ 2,384.6	$ 3,654.5	$ 15,898.8
27	Transmission Costs ($ x 1000)	$ 263.0	$ 255.2	$ 84.5	$ 95.0	$ 32.5	$ 16.2	$ 36.6	$ 6.3	$ 27.4	$ 25.6	$ 115.4	$ 188.7	$ 1,146.5
28	Revenue Excluding Transmission Costs ($ x 1000)	$ 2,428.4	$ 1,905.5	$ 746.3	$ 1,344.6	$ 488.3	$ 252.1	$ 704.3	$ 205.3	$ 504.9	$ 437.4	$ 2,269.3	$ 3,465.9	$ 14,752.3
	Net Hedges													
29	Energy (MWh)	-	-	-	159,200.0	32,400.0	-	-	-	-	-	-	-	191,600.0
30	Cost($ X 1000)	$ -	$ -	$ -	$ 4,229.8	$ 1,134.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,363.8
31	Net Power Supply Expenses ($ x 1000)	$ 4,053.8	$ 4,594.8	$ 9,287.2	$ 23,185.8	$ 23,941.4	$ 13,733.3	$ 11,579.7	$ 19,117.9	$ 22,698.2	$ 16,981.3	$ 7,007.2	$ 4,619.5	$ 160,800.1
32	PURPA ($ x 1000)	$17,176.58	$19,451.45	$21,602.23	$22,935.21	$21,132.72	$18,179.57	$16,191.63	$16,100.42	$15,794.73	$12,316.84	$14,576.81	$13,754.93	$ 209,213.1
33	Total Net Power Supply Expenses ($ x 1000)	$ 21,230.4	$ 24,046.2	$ 30,889.4	$ 46,121.0	$ 45,074.1	$ 31,912.9	$ 27,771.4	$ 35,218.3	$ 38,492.9	$ 29,298.2	$ 21,584.0	$ 18,374.4	$ 370,013.190
34	Sales at Customer Level (In 000s MWH)	1,027.006	1,048.528	1,229.108	1,472.664	1,552.659	1,385.654	1,109.193	1,031.240	1,152.209	1,277.132	1,213.385	1,105.482	14,604.270
35	Hours in Month	720	744	720	744	744	720	744	720	744	744	572	744	8760
36	Unit Cost / MWH (for PCAM)	$20.67	$22.93	$25.13	$31.32	$29.03	$23.03	$25.04	$34.15	$33.41	$22.94	$17.79	$15.62	$25.34
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
37	Portion of Purchased Power considered HL Purchases	2.27%	16.19%	34.96%	19.69%	26.40%	36.02%	37.19%	41.16%	17.19%	14.82%	13.40%	1.45%	
38	Purchased Power HL Price	12.00	10.96	13.04	19.43	24.31	22.70	21.66	23.95	28.26	26.55	26.08	22.13	
39	Portion of Surplus Sales considered HL Surplus Sales	75.81%	68.55%	68.85%	84.28%	92.91%	63.56%	55.45%	50.71%	94.15%	85.98%	78.99%	76.55%	
40	Surplus Sales HL Price	11.13	10.17	12.10	18.03	22.55	21.06	20.10	22.22	26.22	24.63	24.20	20.53	
	Light Load													
41	Portion of Purchased Power considered LL Purchases	97.73%	83.81%	65.04%	80.31%	73.60%	63.98%	62.81%	58.84%	82.81%	85.18%	86.60%	98.55%	
42	Purchased Power LL Price	8.19	5.52	6.85	12.21	19.12	19.22	19.76	21.15	24.79	23.29	23.94	20.24	
43	Portion of Surplus Sales considered LL Surplus Sales	24.19%	31.45%	31.15%	15.72%	7.09%	36.44%	44.55%	49.29%	5.85%	14.02%	21.01%	23.45%	
44	Surplus Sales LL Price	7.15	4.81	5.98	10.65	16.67	16.77	17.23	18.45	21.62	20.31	20.87	17.65	

ORDER NO. 16 206

ANNUAL POWER COST UPDATE
April 2016 - March 2017

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,616,871
2	Total Net Power Supply Expense	$349,801,676
3	October APCU Rate ($/MWh)	$23.93
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,604,270
5	Total Net Power Supply Expense	$370,013,190
6	March Forecast Rate ($/MWh)	$25.34
7	Sales Adjusted Forecast Power Cost Change	$20,592,021
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$19,562,420
10	**March Forecast Rate Adjustment ($/MWh)**	$1.34
11	**Combined Rate ($/MWh)**	$25.27

Idaho Power Company
Rate Spread Exhibit for October Update APCU -- O&M Outside AURORA

General Rate Case (UE 233): Marginal Cost-of-Service Study and Stipulated Revenue Spread
2011 Test Period

Line	Description	[A] TOTAL SYSTEM	[B] RESIDENTIAL [1]	[C] GEN SRV [7]	[D] GEN SRV SECONDARY [9-S]	[E] GEN SRV PRIMARY [9-P]	[F] GEN SRV TRANS [9-T]	[G] AREA LIGHTING [15]	[H] LG POWER PRIMARY [19-P]	[I] LG POWER TRANS [19-T]	[J] IRRIGATION SECONDARY [24-S]	[K] UNMETERED GEN SERVICE [40]	[L] MUNICIPAL ST LIGHT [41]	[M] TRAFFIC CONTROL [42]
1	Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	Current Revenue	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	Demand Related Marginal Cost													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	Energy Related Marginal Cost													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	Simple-Summed Energy-Related and Demand-Related Marginal Costs													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	Customer Related Marginal Cost	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	Total Functionalized Revenue Requirement													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	Total Staff-Adjusted Allocation	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	Revenue Deficiency - Staff Adj. Allocation	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	% Increase Required by Staff Adj. Alloc. Approach	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	$ Increase Recommended per Stipulation	$1,810,850	$862,348	$44,153	$197,517	$22,598	$0	$0	$232,545	$212,777	$235,318	$44	$3,507	$84
34	% Increase Recommended per Stipulation	**4.54%**	**5.62%**	**2.83%**	**2.83%**	**2.83%**	**0.00%**	**0.00%**	**2.83%**	**6.81%**	**6.81%**	**4.56%**	**2.83%**	**6.81%**
35	Average Rate Given Stipulation ($/kWh)	0.0641	0.0816	0.0899	0.0628	0.0544	0.0547	0.2324	0.0471	0.0450	0.0791	0.0788	0.1637	0.0805
36	Final Revenue Allocation	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	**Spread Floors and Ceilings:**													
39	No increase for those warranting a decrease greater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													

2016 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures

Line	Description	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
42	2016 October Update APCU Cost of Service (Allocator – Line 14)	$337,322	$110,943	$9,120	$58,026	$7,307	$1,305	$187	$80,525	$39,027	$30,566	$6	$302	$9
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	0.81%	0.68%	0.57%	0.81%	0.89%	0.84%	0.17%	0.95%	1.17%	0.83%	0.61%	0.24%	0.60%
44	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
45	2016 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 44))	0.519	0.558	0.511	0.508	0.484	0.461	0.387	0.449	0.526	0.655	0.480	0.388	0.483
46	APCU Incremental Rate for 2016 October Update (Mills per kWh) (Line 45*(Column A:(Line 44/Line 47)))	**0.490**	**0.582**	**0.490**	**0.484**	**0.383**	**0.517**	**0.423**	**0.494**	**0.367**	**0.457**	**1.113**	**0.327**	**0.374**
47	*Loss-Adjusted 2016-2017 Normalized Sales (kWh)*	688,412,209	190,548,481	18,605,426	119,961,908	19,082,992	2,526,070	443,024	163,113,247	106,358,304	66,823,696	5,568	922,474	21,019
48	Projected October Update APCU 2016-2017 Revenues (Line 46 * Line 47)	$337,322	$110,943	$9,120	$58,026	$7,307	$1,305	$187	$80,525	$39,027	$30,566	$6	$302	$9

Notes:

1 2016 October Update APCU Revenues = $0.49/MWh x 688,412.209 MWhs = $ 337,322 (Line 52, Column A)

2 $0.49 =$23.93 (2016 October Update) - $23.44 (2015 October APCU Rate)

ORDER NO. 16 206

Idaho Power Company
Rate Spread Exhibit for March Forecast APCU

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

2011 Test Period

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL [1]	(C) GEN SRV [7]	(D) GEN SRV SECONDARY [9-S]	(E) GEN SRV PRIMARY [9-P]	(F) GEN SRV TRANS [9-T]	(G) AREA LIGHTING [15]	(H) LG POWER PRIMARY [19-P]	(I) LG POWER TRANS [19-T]	(J) IRRIGATION SECONDARY [24-S]	(K) UNMETERED GEN SERVICE [40]	(L) MUNICIPAL ST LIGHT [41]	(M) TRAFFIC CONTROL [42]
1	Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	Current Revenue	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	Demand Related Marginal Cost													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,818	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	Energy Related Marginal Cost													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$646,911	$117,745	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	Simple-Summed Energy-Related and Demand-Related Marginal Costs													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	Customer Related Marginal Cost	$2,805,503	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	Total Functionalized Revenue Requirement													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,966	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,776	$83	$14	$21,953	$42	$83,209	$83
29														
30	Total: Staff-Adjusted Allocation	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	Revenue Deficiency - Staff Adj. Allocation	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	% Increase Required by Staff Adj. Alloc. Approach	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	$ Increase Recommended per Stipulation	$1,810,890	$862,348	$44,153	$197,517	$22,598	$0	$0	$232,545	$212,777	$235,318	$44	$3,507	$84
34	% Increase Recommended per Stipulation	4.54%	5.62%	2.83%	2.83%	2.83%	0.00%	0.00%	2.83%	6.81%	6.81%	4.56%	2.83%	6.81%
35	Average Rate Given Stipulation ($/kWh)	0.0641	0.0816	0.0899	0.0628	0.0544	0.0547	0.2324	0.0471	0.0450	0.0791	0.0788	0.1637	0.0805
36	Final Revenue Allocation	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	**Spread Floors and Ceilings:**													
39	No increase for those warranting a decrease greater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													

2016 March Forecast APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL [1]	(C) GEN SRV [7]	(D) GEN SRV SECONDARY [9-S]	(E) GEN SRV PRIMARY [9-P]	(F) GEN SRV TRANS [9-T]	(G) AREA LIGHTING [15]	(H) LG POWER PRIMARY [19-P]	(I) LG POWER TRANS [19-T]	(J) IRRIGATION SECONDARY [24-S]	(K) UNMETERED GEN SERVICE [40]	(L) MUNICIPAL ST LIGHT [41]	(M) TRAFFIC CONTROL [42]
42	2016 March Forecast APCU Cost of Service (Allocator -- Line 14)	$922,472	$303,395	$24,939	$158,684	$19,982	$3,568	$513	$220,212	$106,726	$83,588	$17	$826	$21
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	2.21%	1.87%	1.56%	2.21%	2.43%	2.30%	0.46%	2.61%	3.20%	2.27%	1.67%	0.65%	1.63%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$42,606,953	$16,521,675	$1,628,492	$7,332,116	$840,682	$158,565	$112,975	$8,665,822	$3,442,896	$3,773,177	$1,033	$128,184	$1,336
45	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
46	2016 March Forecast Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) [1000*(Line 42/Line 45)]	1.419	1.526	1.398	1.389	1.323	1.260	1.059	1.229	1.439	1.792	1.314	1.061	1.316
47	APCU Incremental Rate for 2016 March Forecast (Mills per kWh) (Line 46*[Column A:[Line 45/Line 48]])	**1.340**	**1.592**	**1.340**	**1.323**	**1.047**	**1.413**	**1.157**	**1.350**	**1.003**	**1.251**	**3.044**	**0.895**	**1.022**
48	*Loss-Adjusted 2016-2017 Normalized Sales (kWh)*	688,412,209	190,548,481	18,605,426	119,961,908	19,082,992	2,526,070	443,024	163,113,247	106,358,304	66,823,695	5,568	922,474	21,019
49	Projected March Forecast APCU 2016-2017 Revenues (Line 47 * Line 48)	$922,472	$303,395	$24,939	$158,684	$19,982	$3,568	$513	$220,212	$106,726	$83,588	$17	$826	$21

Notes:

1 2016 March Forecast APCU Revenues = $1.34/MWh x 688,412,209 MWhs = $ 922,472 (Line 49, Column A)

ORDER NO. 16 206

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2016

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	13,694	190,548,481	$18,948,137	99.44	$101,181	$19,049,318	99.97	0.53%
2	Small General Service	7	2,531	18,605,426	$1,969,491	105.86	$6,772	$1,976,263	106.22	0.34%
3	Large General Service	9	913	141,570,970	$10,924,451	77.17	$57,228	$10,981,679	77.57	0.52%
4	Dusk to Dawn Lighting	15	0	443,024	$110,409	249.22	$181	$110,591	249.63	0.16%
5	Large Power Service	19	6	269,471,551	$16,553,536	61.43	$75,908	$16,629,444	61.71	0.46%
6	Agricultural Irrigation Service	24	1,856	66,823,696	$6,546,289	97.96	$67	$6,546,356	97.96	0.00%
7	Unmetered General Service	40	2	5,568	$537	96.51	$10	$547	98.24	1.79%
8	Street Lighting	41	25	922,474	$145,239	157.45	$311	$145,550	157.78	0.21%
9	Traffic Control Lighting	42	8	21,019	$1,997	95.02	$7	$2,004	95.34	0.34%
10	Total Uniform Tariffs		19,035	688,412,209	$55,200,087	80.18	$241,665	$55,441,752	80.54	0.44%
12	Total Oregon Retail Sales		19,035	688,412,209	$55,200,087	80.18	$241,665	$55,441,752	80.54	0.44%

ORDER NO. 16 208

(1) Updated April 2016-March 2017 Test Year

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2016

Summary of Revenue Impact - Rates 9, 19, and 24 Distribution Level Detail
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:									
1	Large General Secondary	9S	907	119,961,908	$9,421,862	78.54	$51,344	$9,473,205	78.97	0.54%
2	Large General Primary	9P	5	19,082,992	$1,330,473	69.72	$4,599	$1,335,072	69.96	0.35%
3	Large General Transmission	9T	1	2,526,070	$172,117	68.14	$1,286	$173,402	68.65	0.75%
4	Total Schedule 9		913	141,570,970	$10,924,451	77.17	$57,228	$10,981,679	77.57	0.52%
6	Large Power Secondary	19S	0	0	$0	0.00	$0	$0	0.00	0.00%
7	Large Power Primary	19P	5	163,113,247	$10,208,256	62.58	$56,763	$10,265,019	62.93	0.56%
8	Large Power Transmission	19T	1	106,358,304	$6,345,281	59.66	$19,144	$6,364,425	59.84	0.30%
9	Total Schedule 19		6	269,471,551	$16,553,536	61.43	$75,908	$16,629,444	61.71	0.46%
11	Irrigation Secondary	24S	1,856	66,823,696	$6,546,289	97.96	$67	$6,546,356	97.96	0.00%
12	Irrigation Transmission	24T	0	0	$0	0.00	$0	$0	0.00	0.00%
13	Total Schedule 24		1,856	66,823,696	$6,546,289	97.96	$67	$6,546,356	97.96	0.00%

ORDER NO. 16 206