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January 25, 2013

VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: UE 257 In The Matter of IDAHO POWER COMPANY's 2013 Annual Power Cost Update

Attention Filing Center:

Enclosed for filing in the above-referenced matter is an original and five copies of the Partial Stipulation.

A copy of this filing has been served on all parties to the service list. Please contact this office with any questions.

Very truly yours,

Wendy McIndoo
Office Manager

Enclosures
cc: Service List

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 257

In the Matter of:

PARTIAL STIPULATION

Idaho Power Company's 2013 Annual Power Cost Update

7 This Partial Stipulation resolves all issues among the parties to this Partial Stipulation
8 related to Idaho Power Company's ("Idaho Power" or "Company") October Update component
9 of the 2013 Annual Power Cost Update ("APCU") filed pursuant to Order No. 08-238.¹ The
10 APCU updates the Company's net power supply expense and results in new rates, to be
11 effective June 1, 2013.

PARTIES

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

BACKGROUND

17 2. Pursuant to Order No. 08-238, Idaho Power annually updates its net power
18 supply expense included in rates through an automatic adjustment clause, the APCU. The
19 APCU is comprised of two components—an “October Update” and a “March Forecast.” The
20 October Update contains the Company’s forecasted net power supply expense reflected on a
21 normalized unit basis for an April through March test period. The March Forecast contains the
22 Company’s net power supply expense based upon updated actual forecasted conditions.
23 Pursuant to Order No. 10-191² the Company allocates the APCU revenue requirement to

²⁴ 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).

²⁶ ² *Re Idaho Power Company's 2010 Annual Power Cost Update*, Docket UE 214, Order No. 10-191 (May 24, 2010).

1 individual customer classes on the basis of the total generation-related revenue requirement
2 approved in the Company's last general rate case, instead of the previous equal cents per
3 kWh approved in Order No. 08-238. Order No. 10-191 also directs the Company to adjust its
4 base rates to reflect changes in revenue requirement related to the October Update, while the
5 rates resulting from the March Forecast are listed on Schedule 55. The rates associated with
6 the October Update and the March Forecast become effective on June 1 of each year.

7 3. On October 24, 2012, Idaho Power filed testimony and exhibits for the 2013
8 APCU ("2013 October Update").³ Pursuant to Order No. 08-238 the 2013 October Update
9 updated the following variables: loads, fuel prices, transportation costs, maintenance rates,
10 heat rates, and forced outage rates for thermal plants.⁴ The test period for the 2013 October
11 Update was April 2013 through March 2014 and included updated plant capacities for all
12 Company owned resources and updated sales and load forecast.⁵ The 2013 October Update
13 specifically accounted for changes in natural gas and coal prices, generation and expenses
14 related to contracts entered into pursuant to the Public Utility Regulatory Policies Act of 1978
15 ("PURPA"), and the addition of the costs and benefits associated with the Langley Gulch
16 power plant and Neal Hot Springs geothermal PPA.⁶

17 4. The 2013 October Update resulted in a cost per unit of \$23.41 per megawatt-
18 hour ("MWh").⁷ This represents an increase of \$3.94 per MWh over last year's October
19 Update.⁸

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22 ³ See Idaho Power/100 – 107.

23 ⁴ Idaho Power/100, Wright/2.

24 ⁵ Idaho Power/100, Wright/2.

25 ⁶ Idaho Power/100, Wright/2-3.

26 ⁷ Idaho Power/100, Wright/8.

26 ⁸ Idaho Power/100, Wright/8.

1 5. The 2013 October Update also included the Company's proposed method of
2 allocation, which was consistent with the revenue spread methodology approved by the
3 Commission in Order No. 10-191.⁹

4 6. On October 31, 2012, CUB filed its Notice of Intervention. On November 16,
5 2012, Administrative Law Judge ("ALJ") Lisa Hardie held a prehearing conference at which
6 the parties to Docket UE 257 agreed upon a procedural schedule that would allow the Public
7 Utility Commission of Oregon ("Commission") to issue an order on Idaho Power's 2013 APCU
8 prior to June 1, 2013.¹⁰

9 7. Staff and CUB served discovery on Idaho Power and conducted a thorough
10 investigation of the 2013 October Update. When responding to discovery, the Company
11 revised Exhibits 101, 105 and 106 to include an additional year of hydro generation that was
12 inadvertently omitted from the original filed computations. The original filing made on October
13 24, 2012, included 83 years of hydro generation and should have included the 84 years of
14 hydro data. As a result of this correction, the cost per unit on Exhibit 105 dropped from
15 \$23.41 per MWh to \$23.34 per MWh.

16 8. On January 11 and 16, 2013, the Stipulating Parties conducted two settlement
17 conferences. As a result of these discussions, the parties agreed to the settlement reflected
18 below.

19 9. This Partial Stipulation, presented on behalf of all parties to the docket, resolves
20 all issues in the docket related to the 2013 October Update filed on October 24, 2012.

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25 ⁹ Idaho Power/100, Wright/12; Idaho Power/106.

26 ¹⁰ *Re Idaho Power Company's 2012 Annual Power Cost Update*, Docket UE 242, Prehearing
Conference Memorandum at 1 (Nov. 16, 2012).

AGREEMENT

2 10. Subject to the adjustments discussed below, the Stipulating Parties agree that
3 the Company's 2013 October Update was calculated in conformance with the methodology
4 adopted by the Commission in Order No. 08-238.

5 11. The Stipulating Parties agree to adjust the Company's filed 2013 October Update
6 to include only 6 months (October 2013 – March 2014) of the Dynamis PURPA contract.
7 Attachment 1 to this Partial Stipulation contains the re-dispatch of the AURORA simulation
8 model that includes all 84 years of hydro generation as well as only the inclusion of 6 months
9 of the Dynamis PURPA contract. This adjustment reduces the filed Total Net Power Supply
10 Expenses ("NPSE"), including PURPA, to \$325.2 million, a decrease of \$3 million on a total
11 system basis. Attachment 1 and Attachment 2 to this Partial Stipulation present the results of
12 these calculations.

13 12. The Company will file its March Forecast consistent with the schedule adopted
14 by ALJ Hardie on November 16, 2012. Staff and CUB reserve the right to challenge all
15 elements of the March Forecast and will do so in accordance with the schedule adopted by
16 ALJ Hardie on November 16, 2012.

17 13. The Stipulating Parties agree that the Company's allocation methodology
18 conforms to that adopted by the Commission in Order No. 10-191. The results of this
19 allocation are set forth in Attachment 3 to this Partial Stipulation. The result of the agreed
20 upon adjustment changes the Oregon share of APCU revenues from \$2.5 million to \$2.4
21 million, a reduction of nearly \$100,000.

22 14. For purposes of this Partial Stipulation, the Stipulating Parties agree that Idaho
23 Power's method of repricing PURPA contracts executed in Idaho to reflect Oregon's non-
24 levelized methodology is reasonable.

25 15. The Stipulating Parties agree to submit this Partial Stipulation to the Commission
26 and request that the Commission approve the Partial Stipulation as presented. The

1 Stipulating Parties agree that the adjustments and the rates resulting from the Partial
2 Stipulation are fair, just, and reasonable.

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

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

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

21 19. By entering into this Partial Stipulation, no Stipulating Party shall be deemed to
22 have approved, admitted, or consented to the facts, principles, methods, or theories employed
23 by any other Stipulating Party in arriving at the terms of this Partial Stipulation, other than
24 those specifically identified in the body of this Partial Stipulation. No Stipulating Party shall be
25 deemed to have agreed that any provision of this Partial Stipulation is appropriate for
26

1 resolving issues in any other proceeding, except as specifically identified in this Partial
2 Stipulation.

3 20. This Partial Stipulation may be executed in counterparts and each signed
4 counterpart shall constitute an original document.

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

7

8 STAFF

9 By: Mae C. Lin (attorney)
10 Date: 1/24/13

12 IDAHO POWER

CITIZENS' UTILITY BOARD OF OREGON

13 By: _____
14 Date: _____

By: _____
Date: _____

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7

8 STAFF

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10 By: _____

11

Date: _____

12

IDAHO POWER

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By:  _____

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Date: 1-25-13

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CITIZENS' UTILITY BOARD OF OREGON

By: _____

Date: _____

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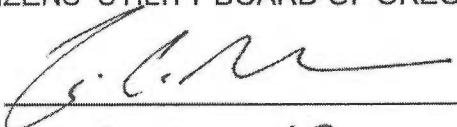
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8 STAFF

9
10 By: _____
11 Date: _____

12 IDAHO POWER
13 By: _____
14 Date: _____
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CITIZENS' UTILITY BOARD OF OREGON

By: 
Date: 1-24-13

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Docket UE 257

Attachment 1

to

Partial Stipulation

January 25, 2013

Attachment 1 to Partial Stipulation

Idaho Power/101
Wright/1

IPCO POWER SUPPLY COSTS FOR APRIL 2013 - MARCH 2014 NORMALIZED LOADS OVER 84 WATER YEAR CONDITIONS

AVERAGE

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)													
Bridger Energy (MWh) Cost (\$ x 1000)	\$ 856,155.7	954,893.9	899,010.8	674,604.0	507,197.1	539,308.3	551,515.6	485,796.1	673,443.5	756,766.5	827,276.0	839,201.9	8,545,169.3
Boardman Energy (MWh) Cost (\$ x 1000)	\$ 152,970.8	230,368.0	257,493.2	405,810.8	432,422.7	389,455.7	395,001.2	403,120.6	394,476.2	355,608.3	278,975.5	284,580.0	3,960,281.0
Valmy Energy (MWh) Cost (\$ x 1000)	\$ 3,662.4	5,491.0	\$ 6,041.3	\$ 9,091.5	\$ 9,631.9	\$ 8,732.0	\$ 8,872.1	\$ 9,036.9	\$ 8,833.9	\$ 8,377.2	\$ 6,676.9	\$ 6,802.1	\$ 91,249.2
Langley Gulch Energy (MWh) Cost (\$ x 1000)	\$ 13,112.7	9,864.4	28,221.6	40,360.7	41,578.5	40,182.0	41,088.4	40,094.5	40,560.5	17,325.8	13,264.0	14,382.5	340,035.5
Danskin Energy (MWh) Cost (\$ x 1000)	\$ 302.6	\$ 220.4	\$ 616.2	\$ 845.5	\$ 868.0	\$ 839.0	\$ 858.9	\$ 837.4	\$ 849.2	\$ 561.4	\$ 446.9	\$ 486.1	\$ 7,731.7
Bennett Mountain Energy (MWh) Cost (\$ x 1000)	\$ 20,913.3	39,380.5	50,461.4	1,917.7	\$ 3,441.2	\$ 3,674.7	\$ 103,473.8	\$ 76,021.8	\$ 69,980.2	\$ 70,515.7	\$ 79,682.4	\$ 65,482.7	52,308.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	\$ 566.4	2,760.9	34,222.9	146,478.8	145,406.8	37,285.1	6,8	-	-	1.7	-	-	-
Contract Energy (MWh)	\$ 46,887.5	46,923.3	43,472.0	46,370.2	44,532.7	40,051.4	45,541.0	51,536.6	53,680.7	39,854.2	44,984.2	46,914.2	3,96,069.3
Total Energy Excl. CSPP (MWh)	\$ 47,253.9	49,584.2	77,694.8	192,849.1	189,999.5	77,336.5	45,547.8	51,581.1	54,135.2	45,037.2	47,071.0	49,656.7	
Market Cost (\$ x 1000)	\$ 23.6	\$ 126.6	\$ 1,877.7	\$ 12,459.8	\$ 11,689.9	\$ 2,921.0	\$ 0.3	\$ 2.0	\$ 781.9	\$ 650.5	\$ 3.1	\$ 6.7	\$ 30,533.1
Contract Cost (\$ x 1000)	\$ 2,457.1	\$ 2,479.5	\$ 3,162.3	\$ 4,021.0	\$ 3,899.7	\$ 2,966.7	\$ 3,304.8	\$ 4,332.3	\$ 4,526.8	\$ 2,710.6	\$ 3,310.0	\$ 2,565.9	\$ 39,756.4
Total Cost Excl. CSPP (\$ x 1000)	\$ 2,480.7	\$ 2,866.1	\$ 5,040.0	\$ 16,480.8	\$ 15,569.6	\$ 5,887.7	\$ 3,305.1	\$ 4,354.2	\$ 5,318.7	\$ 3,361.1	\$ 3,313.1	\$ 2,572.6	\$ 70,289.6
Surplus Sales Energy (MWh)	\$ 345,257.1	383,240.9	201,788.8	21,421.2	14,650.2	183,419.0	366,384.4	219,301.3	141,818.8	158,045.2	339,940.8	380,047.4	2,755,315.0
Revenue Including Transmission Costs (\$ x 1000)	\$ 11,088.0	\$ 11,906.3	\$ 6,498.5	\$ 981.7	\$ 741.5	\$ 7,477.7	\$ 17,754.0	\$ 10,547.1	\$ 8,488.7	\$ 7,170.9	\$ 14,527.2	\$ 15,444.0	\$ 112,635.5
Transmission Costs (\$ x 1000)	\$ 345.3	\$ 383.2	\$ 201.8	\$ 21.4	\$ 14.7	\$ 183.4	\$ 366.4	\$ 219.3	\$ 141.8	\$ 158.0	\$ 339.9	\$ 380.0	\$ 2,755.3
Revenue Excluding Transmission Costs (\$ x 1000)	\$ 10,742.7	\$ 11,523.1	\$ 6,286.7	\$ 980.3	\$ 726.8	\$ 7,294.3	\$ 17,387.6	\$ 10,327.8	\$ 8,356.8	\$ 7,012.9	\$ 14,187.2	\$ 15,083.9	\$ 109,880.2
Net Power Supply Costs (\$ x 1000)	\$ 63.7	\$ 1,658.6	\$ 10,704.3	\$ 33,986.9	\$ 34,236.2	\$ 15,349.8	\$ 2,762.2	\$ 11,691.0	\$ 15,692.9	\$ 13,298.5	\$ 2,480.1	\$ 1,023.8	\$ 142,929.9

Docket UE 257

Attachment 2

to

Partial Stipulation

January 25, 2013

Idaho Power/105 Wright/1

Attachment 2 to Partial Stipulation

IPCO POWER SUPPLY COSTS FOR APRIL 1, 2013 – MARCH 31, 2014 (Multiple Gas Prices/84 Years of Hydro)
Repriced Using UEP95 Settlement Methodology - October Update

AVERAGE
REVISED

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	954,893.9	899,010.8	674,604.0	507,197.1	539,308.3	551,515.6	465,796.1	673,443.5	756,786.5	827,276.0	699,201.9	8,545,169.3	
Bridger Energy (MWh) Cost (\$ x 1000)	\$ 152,970.8	\$ 230,386.0	\$ 257,493.2	\$ 405,810.8	\$ 432,422.7	\$ 389,455.7	\$ 395,001.2	\$ 384,476.2	\$ 403,120.6	\$ 365,608.3	\$ 278,975.5	\$ 284,580.0	\$ 3,980,281.0
Boardman Energy (MWh) Cost (\$ x 1000)	\$ 3,662.4	\$ 5,491.0	\$ 6,041.3	\$ 9,091.5	\$ 9,631.9	\$ 8,732.0	\$ 8,872.1	\$ 8,853.9	\$ 9,036.9	\$ 8,377.2	\$ 6,676.9	\$ 6,802.1	\$ 91,249.2
Valmy Energy (MWh) Cost (\$ x 1000)	\$ 13,112.7	\$ 302.6	\$ 220.4	\$ 40,360.7	\$ 845.5	\$ 41,578.5	\$ 40,182.0	\$ 41,038.4	\$ 40,094.5	\$ 40,505.0	\$ 17,325.8	\$ 13,264.0	\$ 14,382.5
Langley Gulch Energy (MWh) Cost (\$ x 1000)	\$ 20,913.3	\$ 797.9	\$ 1,488.8	\$ 50,461.4	\$ 95,917.5	\$ 103,473.8	\$ 76,021.8	\$ 69,960.2	\$ 70,151.7	\$ 79,662.4	\$ 65,482.7	\$ 52,308.5	\$ 48,805.4
Danskin Energy (MWh) Cost (\$ x 1000)	\$ 93,700.9	\$ 3,060.0	\$ 88,476.7	\$ 88,377.1	\$ 135,311.7	\$ 140,534.0	\$ 114,508.7	\$ 117,078.0	\$ 114,684.3	\$ 122,921.4	\$ 107,663.8	\$ 78,257.1	\$ 80,881.7
Bennett Mountain Energy (MWh) Cost (\$ x 1000)	\$ 66.9	\$ 466.9	\$ 478.2	\$ 478.2	\$ 2,909.6	\$ 4,480.6	\$ 4,682.2	\$ 3,894.2	\$ 4,613.0	\$ 5,145.1	\$ 4,628.9	\$ 3,408.6	\$ 3,498.5
Purchased Power (Excluding CSPP) Market Energy (MWh) Contract Energy (MWh) Total Energy Excl. CSPP (MWh)	566.4	46,987.5	48,823.3	48,584.2	34,222.9	43,478.8	45,406.8	37,285.1	6.8	51,445	14,887.7	14,181.0	155.5
Market Cost (\$ x 1000)	\$ 17.1	\$ 2,457.1	\$ 2,479.5	\$ 2,550.0	\$ 673.3	\$ 5,307.0	\$ 5,935.4	\$ 4,984.1	\$ 40,051.4	\$ 51,536.0	53,680.7	39,954.2	44,984.2
Contract Cost (\$ x 1000)	\$ 2,474.1	\$ 2,474.1	\$ 2,474.1	\$ 2,474.1	\$ 3,162.3	\$ 4,021.0	\$ 3,899.7	\$ 2,966.7	\$ 3,304.8	\$ 4,450.7	51,581.1	54,135.2	45,037.2
Total Cost Excl. CSPP (\$ x 1000)	\$ 345,257.1	\$ 9,438.3	\$ 8,879.8	\$ 8,495.3	\$ 383.409	\$ 201,788.6	\$ 21,421.2	\$ 183,419.0	\$ 14,650.2	\$ 1,452.3	\$ 4,526.8	\$ 610.4	\$ 3,0
Surplus Sales Energy (MWh) Revenue Including Transmission Costs (\$ x 1000) Transmission Costs (\$ x 1000) Revenue Excluding Transmission Costs (\$ x 1000)	\$ 9,093.1	\$ 9,093.1	\$ 8,495.6	\$ 8,495.6	\$ 3,597.0	\$ 703.6	\$ 542.2	\$ 6,320.3	\$ 13,099.6	\$ 8,148.9	\$ 5,800.4	\$ 6,169.5	\$ 12,997.4
Hoku First Block Revenues Net Hedges Energy (MWh) Cost (\$ x 1000)	\$ 1,706.9	\$ 15,785.5	\$ 18,006.7	\$ 12,401.5	\$ 27,094.2	\$ 18,475.5	\$ 16,462.4	\$ 14,706.8	\$ 14,089.0	\$ 15,253.0	\$ 12,310.6	\$ 14,259.8	\$ 4,409.7
Net Power Supply Costs (\$ x 1000)	\$ 12,290.9	\$ 13,997.8	\$ 20,414.5	\$ 30,408.1	\$ 45,839.7	\$ 45,163.3	\$ 29,477.0	\$ 21,986.2	\$ 29,442.0	\$ 30,581.2	\$ 26,745.9	\$ 15,819.6	\$ 11,409.8
PURPA (\$ x 1000)	\$ 1,000,535	\$ 1,001,776	\$ 1,167,770	\$ 1,395,693	\$ 1,474,793	\$ 1,342,353	\$ 1,077,825	\$ 1,005,193	\$ 1,135,660	\$ 1,249,058	\$ 1,152,265	\$ 1,058,826	\$ 14,061,616
Total Net Power Supply Expense (\$ x 1000)	\$ 720	\$ 744	\$ 720	\$ 744	\$ 744	\$ 720	\$ 744	\$ 720	\$ 744	\$ 744	\$ 672	\$ 744	\$ 8750
Sales at Customer Level (in 000s MWh)	Unit Cost / MWh (for PCAM)	\$13.99	\$20.38	\$26.04	\$32.84	\$30.62	\$21.96	\$20.38	\$29.29	\$26.93	\$21.41	\$13.73	\$14,47
Prices Used in Purchased Power & Surplus Sales Above:	Heavy Load Portion of Purchased Power considered HL F Purchased Power HL Price	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%
Portion of Surplus Sales considered HL Surpli	62.70% 28.15	62.70% 24.40	62.70% 39.47	62.70% 42.18	62.70% 39.62	62.70% 38.11	62.70% 38.88	62.70% 45.90	62.70% 41.69	62.70% 41.69	62.70% 39.76	62.70% 34.35	62.70% 34.35
Light Load Portion of Purchased Power considered LL P Purchased Power LL Price	35.75% 16.98	35.75% 7.78	35.75% 24.89	35.75% 32.48	35.75% 34.60	35.75% 37.36	35.75% 41.12	35.75% 38.65	35.75% 37.29	35.75% 37.29	35.75% 30.44	35.75% 30.44	35.75% 30.44
Portion of Surplus Sales considered LL Surpli	37.39% 21.26	37.39% 14.81	37.39% 6.78	37.39% 21.70	37.39% 30.17	37.39% 32.58	37.39% 31.79	37.39% 34.58	37.39% 32.52	37.39% 32.52	37.39% 26.55	37.39% 26.55	37.39% 26.55

Docket UE 257

Attachment 3

to

Partial Stipulation

January 25, 2013

Attachment 3 to Partial Stipulation

Idaho Power/106

Wright/1

Idaho Power Company
Rate Spread Exhibit for October Update 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	(C) GEN SERV [2]	(D) GEN SERV SECONDARY [5]	(E) GEN SERV PRIMARY [9]	(F) GEN SERV TRANS [10]	(G) AREA LIGHTING [15]	(H) LG POWER PRIMARY [19-2]	(I) LG POWER TRANS [19-1]	(J) IRRIGATION SECONDARY [24-S]	(K) UNMETERED GEN SERVICE [49]	(L) MUNICIPAL ST LIGHT [41]	(M) TRAFFIC CONTROL [42]							
1	Normalized Sales [kWh]	\$50,158,581	\$198,842,419	\$17,942,896	\$114,256,218	\$15,091,088	\$154,987	\$112,462	\$483,936	\$19,189,047	\$74,155,467	\$3,454,271	\$778,108 \$123,851								
2	Current Revenue	\$53,987,591	\$15,355,592	\$1,559,400	\$1,559,400	\$1,575,915	\$758,102	\$154,987	\$8,213,065	\$3,123,393	\$12,900	\$972	\$16,328 \$1,231								
3	Demand Related Marginal Cost	\$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								
4	Generation - Staff Adj.	\$12,432,118	\$4,593,297	\$301,584	\$1,880,300	\$233,817	\$39,838	\$703	\$2,014,458	\$1,669,482	\$1,697,153	\$177	\$1,365 \$225								
5	Transmission - Staff Adj.	\$6,945,625	\$3,215,110	\$181,233	\$3,319,947	\$100,783	\$0	\$5,738	\$798,346	\$0	\$1,314,267	\$161	\$930 \$89								
6	Distribution	\$28,547,004	\$8,940,577	\$802,452	\$5,140,232	\$699,911	\$117,743	\$21,383	\$7,682,010	\$3,097,424	\$3,079,568	\$570	\$34,414 \$722								
7	Energy Related Marginal Cost	\$4,144,040	\$1,297,863	\$116,488	\$746,184	\$94,345	\$17,092	\$3,104	\$11,112,559	\$449,639	\$301,881	\$83	\$4,396 \$105								
8	Transmission - Staff Adj.	\$12	\$12	\$12	\$12	\$12	\$12	\$12	\$12	\$12	\$12	\$12	\$12								
9	Simple-Summed Energy-Related and Demand-Related Marginal Costs	\$39,595,454	\$13,023,020	\$1,070,495	\$6,811,410	\$857,724	\$153,168	\$22,008	\$9,452,425	\$4,581,142	\$3,587,988	\$728	\$35,449 \$922								
10	Generation Marginal Costs - Staff Adj.	\$16,578,157	\$5,891,160	\$418,072	\$2,925,484	\$328,162	\$56,950	\$3,807	\$3,126,717	\$2,119,021	\$1,999,034	\$660	\$6,160 \$350								
11	Transmission Marginal Costs - Staff Adj.	\$2,805,903	\$1,967,110	\$385,570	\$177,410	\$6719	\$1,390	\$0	\$15,208	\$2,535	\$246,967	\$228	\$1,892 \$473								
12	Customer Related Marginal Cost	\$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								
13	Total Functionalized Revenue Requirement	\$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								
14	Generation - Staff Adj.	\$22	\$22	\$22	\$22	\$22	\$22	\$22	\$22	\$22	\$22	\$22	\$22								
15	Transmission	\$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								
16	Distribution	\$2,859,472	\$2,004,665	\$382,931	\$180,797	\$8,847	\$1,417	\$0	\$15,488	\$2,583	\$251,682	\$232	\$1,928 \$890								
17	Demand-Related Customer-Related Allocated	\$419,424	\$188,447	\$94,356	\$12,375	\$69	\$14	\$78,778	\$33	\$21,953	\$42	\$83,209 \$83									
18	Direct Assignment:	\$1,613,429	\$1,449,425	\$6,902,669	\$767,013	\$113,599	\$101,145	\$7,865,094	\$3,464,601	\$4,762,425	\$1,014,515	\$1,728	\$121,310 \$52,541								
19	Total: Staff-Adjusted Allocation	\$1,810,950	\$778,487	\$109,751	\$7,075	\$1,056	\$26,718	\$41,398	\$341,208	\$308,154	\$3,078,154	\$319	\$2,056% 42.91%								
20	Revenue Deficiency - Staff Adj. Allocation	\$1,810,380	\$462,348	\$44,153	\$2,917,517	\$22,598	\$0	\$0	\$232,545	\$212,777	\$38,318	\$44	\$3,507% 54.84%								
21	Increase Recommended by Staff Adj. Alloc. Approach	\$4,54%	5,62%	5,623%	2,833%	0.0%	0.0%	2,833%	0.0%	6,831%	6,831%	4,56%	6,81% 0.0805								
22	Increase Recommended per Stipulation	\$0,0441	\$16,238,280	\$1,603,553	\$7,173,432	\$820,700	\$154,987	\$112,462	\$8,445,610	\$3,336,170	\$3,689,589	\$1,016	\$127,358 \$1,315								
23	Average Rate Given Stipulation (\$/kWh)	\$41,684,481	\$16,238,280	\$1,603,553	\$7,173,432	\$820,700	\$154,987	\$112,462	\$8,445,610	\$3,336,170	\$3,689,589	\$1,016	\$127,358 \$1,315								
24	Final Revenue Allocation	\$37	\$37	\$37	\$37	\$37	\$37	\$37	\$37	\$37	\$37	\$37	\$37								
25	Spread Floors and Ceilings:	\$39	No increase for those warranting a decrease greater than 8%	\$40	2.8% increase for those warranting a decrease less than 8%	\$41	No increase greater than one-and-one-half times the average increase	\$42	2012 October Update APCU Cost of Service (UE 242)	\$1,298,993	\$127,230	\$35,118	\$223,454	\$28,138	\$5,025	\$310,994	\$150,288	\$117,76	\$24	\$1,163	\$30
26	2013 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures	\$42	2012 October Update APCU Cost of Service (UE 242)	\$1,298,993	\$127,230	\$35,118	\$223,454	\$28,138	\$5,025	\$310,994	\$150,288	\$117,76	\$24	\$1,163	\$30						
27	2013 October Update APCU Cost of Service (Allocator - Line 14)	\$2,409,527	\$792,478	\$65,142	\$414,488	\$57,139	\$9,321	\$1,339	\$575,200	\$278,772	\$218,335	\$44	\$2,157	\$56							
28	% Increase Required Due to APCU (Proposed) (Line 43/(Line 36))	5.78%	4.89%	4.06%	5.78%	6.36%	6.01%	1.19%	6.11%	5.36%	5.32%	4,36%	1.69%	4.27%							
29	Proposed Combined Revenue Spread (Line 36 + Line 42 + Line 43)	\$45,393,000	\$17,437,388	\$1,703,813	\$7,811,374	\$901,032	\$169,342	\$114,523	\$9,330,904	\$3,765,230	\$4,025,630	\$1,084	\$130,678	\$1,401							
30	Total: Staff-Adjusted Allocation	\$650,158,581	198,842,419	17,842,896	114,256,218	15,091,088	2,852,509	483,936	179,189,047	74,155,467	46,649,265	12,900	\$78,108	16,328							
31	Revenue Deficiency - Staff Adj. Allocation	\$1,810,950	\$778,487	\$109,751	\$7,075	\$1,056	\$26,718	\$41,398	\$341,208	\$308,154	\$3,078,154	\$319	\$2,056% 42.91%								
32	Increase Recommended by Staff Adj. Alloc. Approach	\$1,810,380	\$462,348	\$44,153	\$2,917,517	\$22,598	\$0	\$0	\$232,545	\$212,777	\$38,318	\$44	\$3,507% 54.84%								
33	Increase Recommended per Stipulation	\$4,54%	5,62%	5,623%	2,833%	0.0%	0.0%	2,833%	0.0%	6,831%	6,831%	4,56%	6,81% 0.0805								
34	Percentage Recommended per Stipulation	\$0,0441	\$16,238,280	\$1,603,553	\$7,173,432	\$820,700	\$154,987	\$112,462	\$8,445,610	\$3,336,170	\$3,689,589	\$1,016	\$127,358 \$1,315								
35	Average Rate Given Stipulation (\$/kWh)	\$41,684,481	\$16,238,280	\$1,603,553	\$7,173,432	\$820,700	\$154,987	\$112,462	\$8,445,610	\$3,336,170	\$3,689,589	\$1,016	\$127,358 \$1,315								
36	Final Revenue Allocation	\$37	\$37	\$37	\$37	\$37	\$37	\$37	\$37	\$37	\$37	\$37	\$37								
37	Spread Floors and Ceilings:	\$38	No increase for those warranting a decrease greater than 8%	\$39	2.8% increase for those warranting a decrease less than 8%	\$40	No increase greater than one-and-one-half times the average increase	\$41	2012 October Update APCU Cost of Service (UE 242)	\$1,298,993	\$127,230	\$35,118	\$223,454	\$28,138	\$5,025	\$310,994	\$150,288	\$117,76	\$24	\$1,163	\$30
42	2013 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures	\$42	2012 October Update APCU Cost of Service (UE 242)	\$1,298,993	\$127,230	\$35,118	\$223,454	\$28,138	\$5,025	\$310,994	\$150,288	\$117,76	\$24	\$1,163	\$30						
43	2013 October Update APCU Cost of Service (Allocator - Line 14)	\$2,409,527	\$792,478	\$65,142	\$414,488	\$57,139	\$9,321	\$1,339	\$575,200	\$278,772	\$218,335	\$44	\$2,157	\$56							
44	% Increase Required Due to APCU (Proposed) (Line 43/(Line 36))	5.78%	4.89%	4.06%	5.78%	6.36%	6.01%	1.19%	6.11%	5.36%	5.32%	4,36%	1.69%	4.27%							
45	Proposed Combined Revenue Spread (Line 36 + Line 42 + Line 43)	\$45,393,000	\$17,437,388	\$1,703,813	\$7,811,374	\$901,032	\$169,342	\$114,523	\$9,330,904	\$3,765,230	\$4,025,630	\$1,084	\$130,678	\$1,401							
46	Total: Staff-Adjusted 2011 Normalized Sales (kWh)	\$650,158,581	198,842,419	17,842,896	114,256,218	15,091,088	2,852,509	483,936	179,189,047	74,155,467	46,649,265	12,900	\$78,108	16,328							
47	2013 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh)	\$3,660	4.197	3.513	3.581	3.468	3.336	2.786	3.226	3.448	3.835	3,432	2.765	3,433							
48	APCU Incremental Rate for 2013 October Update (Mills per kWh)	658,340,684	188,841,889	18,540,455	115,757,333	15,048,876	2,793,636	480,998	178,282,611	80,849,225	56,996,611	12,900	780,105	16,345							
49	Loss-Adjusted 2013-2014 Normalized Sales (kWh)	\$41,684,481	\$16,238,280	\$1,603,553	\$7,173,432	\$820,700	\$154,987	\$112,462	\$8,445,610	\$3,336,170	\$3,689,589	\$1,016	\$127,358 \$1,315								
50	Projected October Update APCU 2013-2014 Revenues (Line 48 * Line 49)	\$2,409,527	\$792,478	\$65,142	\$414,488	\$57,139	\$9,321	\$1,339	\$575,200	\$278,772	\$218,335	\$44	\$2,157	\$56							

Notes:

1. 2013 October Update APCU Revenues = \$3.66/kWh x 658,340,684 MW's = \$2,409,527 (Line 42, Column A)

2. \$3.66 = \$23.13 (2013 October APCU Rate) - \$19.47 (2012 October APCU Rate)

CERTIFICATE OF SERVICE

2 I hereby certify that I served a true and correct copy of the foregoing document in
3 Docket UE 257 on the following named person(s) on the date indicated below by email
4 addressed to said person(s) at his or her last-known address(es) indicated below.

5

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13 DATED: January 25, 2013

Wendy McIndoo
Wendy McIndoo
Office Manager

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