ORDER NO: 12 176

ENTERED: MAY 18 2012

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 242

In the Matter of IDAHO POWER COMPANY, 2012 Annual Power Cost Update.	ORDER

DISPOSITION: STIPULATION ADOPTED; ANNUAL POWER COST UPDATE ACKNOWLEDGED

In this order, we adopt a stipulation that resolves all issues related to Idaho Power Company's 2012 Annual Power Cost Update. The stipulation updates the company's net power supply expense and results in new rates effective June 1, 2012. These new rates will result in an average increase of 4.03 percent for Idaho Power's customers in Oregon.

I. BACKGROUND

In Order No. 08-238, this Commission approved a Power Cost Adjustment Mechanism (PCAM) and an Annual Power Cost Update (APCU) for Idaho Power to allow the company the greater ability to recover net power supply expenses in a timely manner. The APCU, at issue in this proceeding, is an automatic adjustment clause to prospectively update Idaho Power's net power supply expenses included in rates for its Oregon customers.

The APCU has two components—the October Update and the 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 expense based upon updated actual forecasted conditions.

The APCU's revenue requirement is allocated to individual customer classes on the basis of the total generation-related revenue requirement approved in the company's last general rate case. Idaho Power adjusts 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 become effective on June 1 of each year.

II. 2012 APCU

On October 20, 2011, Idaho Power filed testimony and exhibits in support of its 2012 APCU. The October Update included updated plant capacities for all company owned resources, updated sales and load forecasts, changes in natural gas and coal prices, and expenses related to contracts entered into pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA). The October Update also included the costs and benefits associated with Idaho Power's new Langley Gulch power plant—a 300 megawatt (MW) combined-cycle natural gas plant that is currently under construction.

On March 22, 2012, Idaho Power filed its 2012 March Forecast, which consisted of direct testimony describing the company's updated estimate of the expected net power supply expense. In the March Forecast, the company updated fuel prices, forecast normalized sales and loads, forecast hydro generation, known power purchases and sales, and the forward price curve. The March Forecast included significantly greater PURPA expenses—an increase of nearly 50 percent over last year's March Forecast.

Combining the October Update and the March Forecast, Idaho Power reports a unit cost of $20.77 per megawatt-hour (MWh), which is $2.79 per MWh more than last $17.98 per MWh adopted in the company's 2011 APCU.

The Citizens' Utility Board of Oregon (CUB) and Commission Staff participated as parties in this proceeding. In opening testimony, Staff identified that the large increase in purchases required under PURPA accounted for approximately 70 percent of the increase in Idaho Power's net power supply expense. Staff further identified an increased in Idaho Power's load growth and coal costs as other factors contributing to the increased costs.

Following the filing of testimony and settlement discussions, the parties reached informal resolution of all issues. On May 4, 2011, Idaho Power, CUB, and Staff jointly submitted a stipulation resolving all issues among the parties which resulted in a revised APCU, updating the company's net power supply expense and resulting in new rates, to be effective June 1, 2012. The stipulation is attached as Appendix A. Motions filed by Idaho Power, CUB, and Staff to admit the prefiled testimony and stipulation into the record are hereby granted.

II. STIPULATION

The parties agree to a unit cost of $20.76 per MWh, which is one cent less than the amount calculated by the company by combining the revised 2012 October Update and March Forecast. This amount excludes the costs and benefits associated with the Langley Gulch power plant, which the company agreed to remove because the plant is not scheduled to be online until part way through the test period.

The parties also agree that the calculation of the agreed upon unit cost is correct and in conformance with the methodology adopted in Order No. 08-238, and that the resulting rates are fair, just, and reasonable.

III. DISCUSSION

We have reviewed the testimony and supporting exhibits in this case, the stipulation and the joint explanatory brief. Based on that review, we find that the stipulated unit of $20.76 per MWh conforms to the methodology adopted in Order No. 08-238. We further find that Idaho Power's allocation methodology conforms to the methodology adopted in Order No. 10-191.

Based on those findings, we conclude that the rates resulting from the terms of the stipulation are just and reasonable, and should be made effective on June 1, 2012. These new rates will result in an average increase of 4.03 percent for Idaho Power's customers in Oregon.

IV. ORDER

IT IS ORDERED that:

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

2. The 2012 Annual Power Cost Update is acknowledged as being in compliance with the Commission's rules and prior decisions.

3. Idaho Power Company must file new tariffs consistent with this order to be effective no earlier than June 1, 2012. Advice No. 12-08 is permanently suspended.

Made, entered and effective MAY 18 2012.

John Savage Commissioner	**Susan K. Ackerman** Commissioner
	Stephen M. Bloom Commissioner

A party may request rehearing or reconsideration of this order pursuant to 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 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 242

In the Matter of: Idaho Power Company's 2012 Annual Power Cost Update	**STIPULATION**

This Stipulation resolves all issues among the parties to this Stipulation related to Idaho Power Company's ("Idaho Power" or "Company") 2012 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, to be effective June 1, 2012.

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 Company (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 and 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[2] the Company allocates the APCU revenue requirement to

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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).

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

individual customer classes on the basis of the total generation-related revenue requirement approved in the Company's last general rate case, instead of the previous equal cents per kWh approved in Order No. 08-238. 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 become effective on June 1 of each year.

3. On October 20, 2011, Idaho Power filed testimony and exhibits for the 2012 APCU ("2012 October Update").[3] Pursuant to Order No. 08-238 the 2012 October Update updated the following variables: loads, fuel prices, transportation costs, maintenance rates, heat rates, and forced outage rates for thermal plants.[4] The test period for the 2012 October Update was April 2012 through March 2013 and included updated plant capacities for all Company owned resources and updated sales and load forecast.[5] The 2012 October Update specifically accounted for changes in natural gas and coal prices, generation and expenses related to contracts entered into pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and the addition of the Company's Special Contract with Hoku Materials, Inc. ("Hoku").[6] The 2012 October Update also included the costs and benefits associated with the Company's new Langley Gulch power plant, which is a 300 megawatt ("MW") combined-cycle natural gas plant that is currently under construction. Idaho Power anticipates that the plant will be online in July 2012.[7]

4. The 2012 October Update resulted in a cost per unit of $19.07 per megawatt-hour ("MWh").[8] During discovery Idaho Power discovered an error in how it had calculated its

[3] *See* Idaho Power/100.

[4] Idaho Power/100, Wright/2.

[5] Idaho Power/100, Wright/2.

[6] Idaho Power/100, Wright/2-6.

[7] Idaho Power/100, Wright/3.

[8] Idaho Power/100, Wright/7.

PURPA expenses. Correcting for this error resulted in a reduction of nine cents to the 2012 October Update cost per unit.[9] The October Update unit cost that became effective June 1, 2011, was $16.96 per MWh.[10]

5. On October 27, 2011, CUB filed its Notice of Intervention. On November 28, 2011, Administrative Law Judge Sarah K. Wallace held a prehearing conference at which the parties to Docket UE 242 agreed upon a procedural schedule that would allow the Public Utility Commission of Oregon ("Commission") to issue an order on Idaho Power's 2012 APCU prior to June 1, 2012.[11]

6. Staff and CUB served discovery on Idaho Power and conducted a thorough investigation of the 2012 October Update. On January 25, 2012, Staff and CUB filed Opening Testimony addressing the 2012 October Update. In that testimony, CUB indicated that it had analyzed the 2012 October Update and raised several issues through discovery that were adequately addressed by the Company. CUB also advised that it would review the March Forecast and then determine whether to provide substantive testimony.[12]

7. Staff's testimony discussed the primary factors affecting the Company's requested increase in net power supply expenses. Staff identified the large increase in PURPA contracts, which accounts for approximately 70 percent of the increase, as the primary driver of this year's increase in net power supply expenses.[13] Staff's testimony also described the analysis Staff performed and concluded that the Company's 2012 October Update conformed to the requirements of Order No. 08-238 and that the Company's analysis and calculations were correct.[14]

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[9] Idaho Power/203.

[10] Idaho Power/100, Wright/7.

[11] *Re Idaho Power Company's 2012 Annual Power Cost Update*, Docket UE 242, Prehearing Conference Memorandum at 1 (Nov. 29, 2011).

[12] *See* CUB/100, Feighner/1-2.

[13] *See* Staff/100, Schue/1.

[14] *See* Staff/100, Schue/10.

8. On March 9, 2012, the Company filed an Application and supporting testimony requesting the inclusion of the costs and benefits of Langley Gulch in the Company's revenue requirement. A decision in that docket is expected April 1, 2013.

9. The procedural schedule called for a settlement conference on February 14, 2012, and for all parties to file reply testimony on March 19, 2012. However, because there were no disputes among the parties at that time, the parties cancelled the settlement conference and Chief Administrative Law Judge Michael Grant granted Staff's Motion to Modify the procedural schedule and removed from the schedule the date for parties to file reply testimony.[15]

10. Thereafter, on March 22, 2012, the Company filed its 2012 March Forecast, which consisted of direct testimony describing the Company's estimate of the expected net power supply expense for the upcoming water year—April 2012 through March 2013.[16] 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 2012 October Update, forecast hydro generation, wholesale power purchase and sale contracts, forward price curve, PURPA expenses, and the Oregon state allocation factor.[17]

11. In this year's filing, however, the only variables that had changed since the 2012 October Update were fuel prices, forecast normalized sales and loads, forecast hydro generation, known power purchases and sales, and the forward price curve.[18] The fuel prices were updated to reflect changes in forecast natural gas and coal costs.[19] The sales and load

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[15] *Re Idaho Power Company's 2012 Annual Power Cost Update*, Docket UE 242, Ruling (March 15, 2012).

[16] *See* Idaho Power/200.

[17] Idaho Power/200, Wright/1-2.

[18] Idaho Power/200, Wright/2.

[19] Idaho Power/200, Wright/2-4.

forecast was updated to reflect a revised delivery schedule for Hoku, which resulted in a reduction in the forecast load.[20] The hydro update, based upon updated streamflow forecasts and reservoir levels, reflected the fact that this year's forecasts are slightly lower than last year's.[21] The 2012 March Forecast also included significantly greater PURPA expenses—an increase of nearly 50 percent over last year's March Forecast.[22]

12. In conformance with the requirements of Order No. 08-238, the Company calculated a cost per unit for the 2012 March Forecast of $20.86 per MWh, which is $2.83 per MWh more than last year's cost per unit of $18.03 per MWh.[23]

13. Combining the revised 2012 October Update[24] and 2012 March Forecast resulted in a cost per unit of $20.77 per MWh.[25]

14. The 2012 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.[26]

15. On March 22, 2012, the Company also filed Tariff Advice No. 12-08, which included the revised tariff sheets for the 2012 October Update and March Forecast. The rate effective date on the revised tariff sheets is June 1, 2012.

16. A second settlement conference was scheduled for March 30, 2012 and took place on that date. . While the parties discussed substantive issues the results of the

[20] Idaho Power/200, Wright/4-5.

[21] Idaho Power/200, Wright/5.

[22] Idaho Power/200, Wright/6.

[23] Idaho Power/203.

[24] Rather than the filed $19.07 per MWh that was included in the original 2012 October Update, the calculation reflected in Idaho Power/203 used $18.98, which corrected for an erroneous PURPA expense calculation.

[25] Idaho Power/203.

[26] Idaho Power/200, Wright/7-9; *Re Idaho Power Company's 2010 Annual Power Cost Update*, Docket UE 214, Order No. 10-191 (May 24, 2010).

settlement conference were inconclusive. However, the Company did agree to recalculate some of its proposed numbers and provide those to the parties. Thereafter Staff moved to suspend the schedule and Chief Administrative Law Judge Michael Grant granted Staff's motion.[27]

17. At the time the schedule was suspended CUB was not yet on board with the positions that Staff and the Company were taking. Rather than undo the suspension CUB agreed to wait for the Company's recalculations and to then determine whether CUB was on board with the Staff/Company settlement.

18. On April 26, 2012, the Company provided the promised recalculations in the body of the draft Stipulation. Upon review of the draft Stipulation CUB detemined that it was able to join the Stipulation.

19. This Stipulation, presented on behalf of all parties to the docket, resolves all issues in the docket.

AGREEMENT

20. The Stipulating Parties agree to a cost per unit of $20.76 per MWh, which is one cent less than the amount calculated by the Company by combining the revised 2012 October Update and March Forecast. This amount reflects the Company's filed cost per unit after the removal of the costs and benefits associated with the Langley Gulch power plant. Because the Langley Gulch power plant is not scheduled to be online until part way through the test period, the Stipulating Parties agree to the removal of the costs and benefits associated with the plant from the rates that will be effective June 1, 2012.

21. The Stipulating Parties also agree that the calculation of the agreed upon cost per unit rate is correct and in conformance with the methodology adopted by the Commission in Order No. 08-238 and the Stipulating Parties agree that the rates resulting from the agreed upon cost per unit are fair, just, and reasonable.

[27] *Re Idaho Power Company's 2012 Annual Power Cost Update*, Docket UE 242, Ruling (April 5, 2012).

22. The Stipulating Parties agree that the terms of this Stipulation should be made effective on June 1, 2012.

23. The Stipulating Parties agree that the Company's allocation methodology conforms to that adopted by the Commission in Order No. 10-191. The results of this allocation are set forth in Attachment 1 to this Stipulation.

24. The Stipulating Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Stipulating Parties agree that the adjustments and the rates resulting from the Stipulation are fair, just, and reasonable.

25. 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.

26. If this Stipulation is challenged by any other party to this proceeding, 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.

27. 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.

28. 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.

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

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

STAFF

By: ______________________

Date: May 8, 2012

IDAHO POWER

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________

Date: ______________________

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.

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STAFF

By: ______________________

Date: ______________________

IDAHO POWER

By: ______________________

Date: 5/4/12

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________

Date: 5-4-2012

Idaho Power Company

Docket UE 242

Attachment 1

to

Stipulation

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 [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	$69
8														
9	Energy Related Marginal Cost													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$640,911	$117,749	$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	$2,805,908	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	Total Functionalized Revenue Requirement													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	Total: Staff-Adjusted Allocation	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	Revenue Deficiency - Staff Adj. Allocation	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	% Increase Required by Staff Adj. Alloc. Approach	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	$ Increase Recommended per Stipulation	$1,810,890	$862,346	$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	0.0786	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													

2012 October Update 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	2012 October Update APCU Cost of Service (Allocator -- Line 14)	$1,614,095	$530,865	$43,637	$277,658	$34,964	$6,244	$897	$385,315	$186,744	$146,259	$30	$1,445	$38
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	3.87%	3.27%	2.72%	3.87%	4.26%	4.03%	0.80%	4.56%	5.60%	3.96%	2.92%	1.13%	2.86%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$43,298,575	$16,749,145	$1,647,190	$7,451,089	$855,663	$161,241	$113,359	$8,830,925	$3,522,914	$3,835,847	$1,046	$128,803	$1,352
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	2012 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 45))	2.483	2.670	2.446	2.430	2.316	2.204	1.854	2.150	2.518	3.135	2.299	1.857	2.302
47	APCU Incremental Rate for 2012 October Update (Mills per kWh) (Line 46*(Column A:(Line 45/Line 48)))	**2.510**	**2.776**	**2.418**	**2.464**	**2.386**	**2.235**	**1.866**	**2.293**	**2.441**	**2.530**	**2.299**	**1.852**	**2.299**
48	*Loss-Adjusted 2012-2013 Normalized Sales (kWh)*	643,065,633	191,221,945	18,043,183	112,672,964	14,653,734	2,793,636	480,698	168,063,365	76,507,917	57,818,841	12,900	780,105	16,345
49	Projected October Update APCU 2012-2013 Revenues (Line 47 * Line 48)	$1,614,095	$530,865	$43,637	$277,658	$34,964	$6,244	$897	$385,315	$186,744	$146,259	$30	$1,445	$38

Notes:

1 2012 October Update APCU Revenues = $2.51/MWh x 643,065.633 MW's = $ 1,614,095 (Line 42, Column A)

2 $2.51 = $19.47 (2012 October APCU Rate) - $16.96 (2011 October APCU Rate)

$ 1,298,993 Current Filed Value

	Total
$	2,443,649
$	2,450,080
$	(6,431)

12 176

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	$1,599,400	$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	$525	$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	$1,880,800	$233,817	$39,858	$703	$2,014,453	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,235,110	$181,233	$1,319,947	$100,783	$0	$5,798	$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	$2,915,444	$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	$519,234	$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	$392,933	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$158,447	$34,356	$12,275	$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%	42.01%
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	0.0783	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													

2012 March Forecast 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	2012 March Forecast APCU Cost of Service (Allocator -- Line 14)	$829,555	$272,835	$22,427	$142,701	$17,970	$3,209	$461	$198,030	$95,976	$75,169	$15	$743	$19
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	1.99%	1.68%	1.40%	1.99%	2.19%	2.07%	0.41%	2.34%	2.88%	2.04%	1.50%	0.58%	1.47%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$42,514,035	$16,491,115	$1,625,980	$7,316,132	$838,669	$158,206	$112,923	$8,643,641	$3,432,146	$3,764,757	$1,032	$128,100	$1,334
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	2012 March Forecast Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 45))	1.276	1.372	1.257	1.249	1.190	1.133	0.953	1.105	1.294	1.611	1.181	0.954	1.183
47	APCU Incremental Rate for 2012 March Forecast (Mills per kWh) (Line 46*(Column A:[Line 45/Line 48]))	**1.290**	**1.427**	**1.243**	**1.267**	**1.226**	**1.149**	**0.959**	**1.178**	**1.254**	**1.300**	**1.181**	**0.952**	**1.182**
48	*Loss-Adjusted 2012-2013 Normalized Sales (kWh)*	643,065,633	191,221,945	18,049,183	112,672,964	14,653,734	2,793,636	480,698	168,063,365	76,507,917	57,818,841	12,900	780,105	16,345
49	Projected March Forecast APCU 2012-2013 Revenues (Line 47 * Line 48)	$829,555	$272,835	$22,427	$142,701	$17,970	$3,209	$461	$198,030	$95,976	$75,169	$15	$743	$19

Notes:

1 2012 March Forecast APCU Revenues = $1.29/MWh x 643,065.633 MW's = $ 829,555 (Line 42, Column A)

$ 1,151,087 Current Filed Value