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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2012 THROUGH MAY 31, 2013.	**CASE NO. IPC-E-12-17** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of Record, Donald L. Howell II, Deputy Attorney General, and submits the following comments in response to Order No. 32533 issued on April 25, 2012.

BACKGROUND

Idaho Power Company filed its annual power cost adjustment (PCA) Application on April 13, 2012 for rates to be effective June 1, 2012 through May 31, 2013. The PCA is a symmetrical rate adjustment mechanism that annually adjusts rates to recover a portion of above normal power supply costs from customers, or refund a portion of below normal power supply costs to customers. Idaho Power calculates the total PCA revenue increase in this case to be approximately $43.0 million which would result in an average rate increase of approximately 5.1%. When the proposed PCA increase is combined with the $27.1 million rate credits from the Company's Revenue Sharing case (Case No. IPC-E-12-13), the Company calculates an overall average rate increase for tariff customers (i.e., non-special contract customers) of 1.71%. The net rates are shown in the PCA Schedule No. 55. The annual PCA rate is combined with the Company's "base rates" to produce a customer's overall billing rate.

IDAHO POWER COMPANY'S FILING

PCA Mechanism

The annual PCA mechanism is comprised of three components: 1) a "forecast" that estimates the difference between normal power supply costs embedded in base rates and the coming year's power supply costs; 2) a "true-up" that captures the difference between the previous year's projection and actual power supply costs; and 3) a "reconciliation" of the previous year's true-up to capture the unrecovered or under-refunded amount. Each component is described in more detail below.

1. <u>The Forecast.</u> Forecasted power supply costs for the coming year are based on the Company's most recent Operating Plan and measures the difference between forecasted and normal power supply costs. The power supply cost difference is converted to a cents per kilowatt-hour (¢/kWh) rate by dividing the power costs by projected jurisdictional energy sales. In this PCA case, the Company calculates above normal power supply costs of $70.3 million relative to power supply costs contained in current base rates. After the 95/5 sharing, this produces PCA rates to recover the forecasted above normal power supply costs in the amount of 0.5099 ¢/kWh.

2. <u>The True-up.</u> The true-up amount is the difference between normal and actual power supply costs during the previous year. The previous year's PCA amount is not precisely recovered due to actual power supply costs being different than forecasted power supply costs. The true-up amount is also converted to a ¢/kWh rate by dividing by projected jurisdictional energy sales of 13,172,433 mWh. Idaho Power calculates the true-up amount and rate to be a credit to ratepayers of $17,646,658 and a credit to customers of 0.1340 ¢/kWh, respectively.

3. <u>The Reconciliation.</u> The reconciliation of the true-up tracks the recovery of the previous year's true-up amounts. It nets the actual revenue collected from the true-up rates against the amounts set for recovery. Any difference is carried into the following year's true-up reconciliation along with the true-up difference. Idaho Power calculates the reconciliation of the true-up amount and rate to be a credit to ratepayers of $5,165,169 and 0.0392 ¢/kWh, respectively.

In summary, this year the PCA rate for each class is the combination of the three PCA rate components discussed above, and a Revenue Sharing rate (discussed below). The Company calculates the combination of the three PCA components produces a 2012/2013 PCA rate surcharge of 0.3367 ¢/kWh (0.5099 - 0.1340 - 0.0392).

Revenue Sharing

The Idaho Power Revenue Sharing case (Case No. IPC-E-12-13) is being processed concurrently with this PCA case. In the Revenue Sharing case the Company proposes to credit $27.1 million to Idaho customers. The Company proposes that the Revenue Sharing credit be used to offset the proposed PCA increase. Idaho Power proposes that the Revenue Sharing credit be spread to customer classes on a uniform percent of base revenue basis and applied to reduced energy rates. These energy credits differ for each customer class. This results in a different PCA/Revenue Sharing energy rate for each customer class. These proposed rates are shown on Company Exhibit No. 2. For the four special contract customers, Idaho Power proposes that they each receive a different, flat-monthly credit during the PCA year. The proposed credits are: Micron - $46,803/mo.; Simplot - $18,362/mo.; DOE - $22,906/mo.; and Hoku - $7,685/mo. Atach 2, p.3. These rates are included in Tariff Schedule No. 55 which would be effective June 1, 2012 and would remain in effect for one year.

STAFF AUDIT AND ANALYSIS

A. The PCA Forecast or Projection

The Operating Plan used to forecast power supply costs is based on the most current information available to the Company. It takes many factors into consideration such as water conditions, gas hedges, market purchases, transmission availability, the cost of PURPA contracts, etc. Throughout the year, the Risk Management Committee (RMC) comprised of key Idaho Power employees reviews and updates the Company's risk management strategy. An account by account breakdown of the Company's power supply expense forecast is shown on Attachment A to these comments. The chart shows expenses included in Base Rates, Forecasted Expenses and the Difference. Account 555 – PURPA Purchase Expense, is shown separately from other Account 555 Non-PURPA Expenses because differences in PURPA Contract Expenses are not shared. The entire difference in PURPA QF contracts is passed on to customers.

Attachment B shows Staff's calculation of the PCA rate components. Lines 1 through 18 show the calculation of the Forecast Rate. The forecast rate is the sum of three rate elements. The first element is composed of all PCA amounts subject to 95/5 sharing. Lines 2 through 8 show this calculation. Line 8 shows the first component of the forecast rate to be 0.0005 ¢/kWh.

Lines 10 through 12 show the calculation of the second element of the forecast rate component. The second element includes all amounts, except Demand Response Incentive amounts, that are passed through to customers without sharing. These amounts are almost entirely PURPA QF contract costs. This second rate element is 0.4830 ¢/kWh as shown on line 12. This is by far the largest part of this year's PCA rate increase.

The third forecast rate element is new this year. It is Demand Response Incentives and the calculations are shown on lines 14 through 16. Commission Order No. 32426 allows Idaho Power to capture the difference between base and actual Demand Response Payments in the PCA. This third PCA forecast element is shown on line 16 to be 0.0264 ¢/kWh. These three elements combine to produce the PCA forecast rate component of 0.5099¢/kWh shown on line 18. This rate is almost entirely composed of expected increases in PURPA contract expenses. The Staff agrees with the Company's forecast calculations.

B. The PCA True-Up

The PCA true-up difference is netted against the amount collected from the application of the previous year's true up rates. This difference represents the PCA true-up deferral balance. This deferral balance is divided by expected kWh jurisdictional sales to provide the true-up rate component.

Page 1, lines 4 through 90 of Company Exhibit No. 1 calculates a true-up deferral amount – a credit of $17,646,658. Attachment C contains Staff's verification of the Company's true-up deferral calculations. Staff finds the Company's calculation as shown in Exhibit No. 1 to be correct.

To verify revenues and costs associated with Idaho Power's true-up deferrals, Staff conducted an audit of actual revenues and expenses that occurred during the PCA year (April 1, 2011 through March 30, 2012). These revenues and costs included water lease expenses, fuel expenses for coal, fuel expenses for natural gas, power sales and purchases, third-party transmission expenses, Hoku First Block Energy revenues, Renewable Energy Credits

(RECs) sales, Emission Allowance sales, and Qualifying Facilities (QF) expenses. The Risk Management Operating Plans and RMC minutes were also reviewed.

The following items are included in the PCA true-up component:

1. Load Change Adjustment. This year's true-up calculation includes a negative Load Change Adjustment of $12,621,398. Actual loads during the true-up year were below normal loads in 11 of 12 months. The actual load for the PCA year was below normal by 655,506 MWh. This represents a 4.2% decline in load. The load change adjustment is the product of the negative load growth and the load change adjustment rate (LCAR) of $19.67/MWh for the months of April through December 2011, and $18.16/MWh for January through March 2012. The LCAR is composed of the energy classified fixed costs of production embedded in base rates. When load grows, the adjustment reduces power supply costs to avoid double counting production costs. When load declines, the adjustment reimburses the Company for a portion of lost fixed production costs. The result is that $12,621,398 (before Jurisdictional Allocation and PCA sharing) has been added to the deferral balance for recovery from customers in this year's PCA. This increase due to the LCAR is a cost to customers and is subject to jurisdictional allocation and sharing.

2. Water Leases. The Company sometimes leases water for the production of hydro power from several entities. The increase or decrease in the water lease expense from base rates is included in the PCA for recovery from or credit to customers. This year's PCA deferral balance includes actual water lease expenses of $2,577,915 and the amount included in base rates is $1,825,371, with the difference of $752,544 included in the deferral balance. This increase in water lease expenses from base expenses is a cost to customers and is subject to jurisdictional allocation and sharing.

3. Fuel Expense - Coal. A portion of Idaho Power's electricity comes from coal plants. The three coal plants that Idaho Power owns an interest in are the Bridger, Valmy and Boardman plants. The increase or decrease in the coal expense from base rates is included in the PCA for recovery from or credit to customers. For the audit period of April 2011 to March 2012, the total coal expense for the three plants is $122,922,864. The total coal expense included in base rates is $167,418,061. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $44,495,197. This decrease in coal costs from base costs is a benefit to customers and is subject to jurisdictional allocation and sharing.

4. Fuel Expense - Gas. Idaho Power currently owns and operates several gas-fired combustion turbine generating plants at the Evander Andrews Power Complex (3 Danskin units) and at Bennett Mountain. These plants are located at Mountain Home and currently account for 100% of the Company's natural gas usage.

For the audit period of April 2011 through March 2012, the total variable gas and gas transportation expense for all the gas plants was $10,877,122. The total gas and gas transportation expense included in base rates is $6,051,627. This increase in gas expense from base rates is included in the PCA. In this year's PCA deferral balance, the additional gas expense that is included for future recovery from customers is $4,825,495. This increase in natural gas expenses from base expenses is a cost to customers and is subject to jurisdictional allocation and sharing.

5. Power Sales and Purchases. Staff reviewed the power purchases and sales in conjunction with the Company's Operating Plan. Staff did not find any transaction that was not reasonable or did not follow the Risk Management Committee's recommendations. These transactions were made with an assortment of credit-worthy partners on a timely basis, and there were no transactions conducted with an Idaho Power affiliate.

a. Power Sales. During the PCA year ending March 31, 2012, the Company sold off-system surplus power totaling $96,750,895. The total surplus sales included in base rates is $92,476,391. This increase in the power sales from base rates is included in the PCA. Actual surplus sales were more than base amounts by $4,274,504. This increase in revenues is a benefit to customers and is subject to jurisdictional allocation and sharing.

b. Power Purchases. During the PCA year ending March 31, 2012, the Company made market power purchases, excluding its PURPA contracts. The total amount of power purchases is $62,156,365. The amount of power purchases included in base rates is $66,570,302. Actual power purchases were less than base amounts by $4,413,937. This decrease in costs is a benefit to customers and is subject to jurisdictional allocation and sharing.

6. Third-Party Transmission. In Order No. 30715, the Commission found that third-party transmission costs that are incurred in conjunction with market purchases and off-system sales should be tracked through the PCA like other variable power supply costs. Including transmission expenses in the PCA is a straightforward treatment of power supply costs that fluctuate with power purchases and sales.

For the audit period of April 2011 through March 2012, the actual third-party transmission expense is $6,516,274. The third-party transmission expense included in base rates is $8,247,222. This year's PCA deferral balance includes the difference between actual costs and base costs of $1,730,948. Because the actual costs are less than the amount included in base rates, this amount represents a benefit to customers. This benefit to customers is subject to jurisdictional allocation and sharing.

7. Hoku First Block Energy. In Order No. 32426 (Case No. IPC-E-11-08), the Commission determined that the first block energy revenue from Hoku is to be included in base rates like secondary sales revenue. The variation between what is built into base rates and the actual Hoku revenues are tracked in the PCA. The amount of Hoku First Block Energy revenues included in base rates is $5,773,675. The actual amount of Hoku First Block Energy revenues during the current PCA period is $14,477,351. The actual revenues are more than the amount included in base rates by $8,703,676. These additional revenues are a benefit to customers and are subject to jurisdictional allocation and sharing.

8. Emission Allowance Sales. In Order No. 32424, the Commission ordered that revenues from the sale of emission allowances, plus any applicable interest, be reflected in the PCA and benefit customers by reducing the Company's PCA deferral balance, subject to jurisdictional allocations and sharing. The amount included in the deferral balance is $25,202 and is a benefit to customers.

9. Renewable Energy Credit Sales. In Order No. 30818, the Commission ordered that revenues from the sale of renewable energy credits (RECs) benefit customers and be subject to jurisdictional allocation and sharing. The amount included in the deferral balance is $5,521,597 and is a benefit to customers.

10. Actual PURPA Purchases Including Net Metering and Raft River Expenses. A Qualifying Facility (QF) is a generating facility which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978 (PURPA) and FERC's 18 C.F.R. Part 292, and has obtained certification of its QF status.

For the audit period of April 2011 through March 2012, the actual PURPA expense is $103,846,995. The PURPA expense included in base rates is $62,739,020. The difference between actual PURPA expense and base PURPA expense is included in the PCA for recovery from or credit to customers. In this year's PCA deferral balance, the actual PURPA expense was more than the PURPA expense included in base rates by $41,107,975. This amount is a cost to customers and increases the PCA deferral balance. PURPA contracts are not currently subject to sharing, but they are subject to jurisdictional allocation.

11. Demand Response Incentive Payments. In Order No. 32426 (Case No. IPC-E-11-08), the Commission determined that Demand Response Incentive Payments be included in base rates and that differences between base and actual expenses be tracked through the PCA. Idaho Demand Response Incentive payments are directly assigned to Idaho and are not subject to sharing. For the PCA period (April 2011 to March 2012), there were no actual Demand Response Incentive Payments. The base amount of incentive payments included in base rates during the PCA period is $2,715,842. The difference between the actual amount and the base amount is $2,715,842 and is a benefit to customers.

The Idaho customer true-up Deferral Balance is composed of the following:

Load Change Adjustment	$12,621,398
Water Leases	$752,544
Fuel Expense – Coal	$(44,495,197)
Fuel Expense – Gas	$4,825,495
Surplus Sales	$(4,274,504)
Non-Firm Purchases	$(4,413,937)
Third Party Transmission	$(1,730,948)
Hoku Energy	$(8,703,676)
Subtotal – Change from Base	$(45,418,825)
Emission Allowance Sales Credit	$(25,202)
Renewable Energy Credit Sales	$(5,521,597)
Subtotal – Subject to Jurisdictional Allocation & Sharing	$(50,965,624)
Subtotal - After Jurisdictional Allocation and Sharing	$(45,996,476)
Qualifying Facilities – After Jurisdictional Allocation	$39,052,576
Demand Response Incentive Payments	$(2,715,842)
Total all Expense Items	$(9,659,742)
Revenue from the Forecast	$(7,823,682)
Deferral Balance	$(17,483,424)
Interest on the Deferral Balance	$(163,234)
Deferral Balance (Credit)	**$(17,646,658)**

The Company-proposed true-up rate credit is 0.1340 ¢/kWh. Although Staff calculates the same rate, as shown on Staff Attachment B, line 23, Staff is concerned that the Company does not use actual energy sales to calculate revenue from the previous year's forecast rate. The Company uses normalized energy amounts. The methodology used by the Company has been in use for many years and has been accepted by the Commission as it has approved past PCA rates.

Instead of using normalized energy sales to estimate forecast revenues in determining true-up revenue, Staff believes it may be more appropriate in future PCA years for the Company to use actual energy sales and the approved forecast rate to determine true-up revenue. Staff proposes to immediately initiate discussions with the Company to resolve the issue on a prospective basis.

C. The Reconciliation of the True-Up

The reconciliation of the true-up[1] amount is the difference between what was approved to be collected or refunded when the PCA rate for last year's true-up was set and what was actually collected or refunded. The reconciliation of the true-up may benefit either the Company or customers because any true-up over-collection is returned to customers, and any true-up under-collection is recovered by the Company.

The reconciliation of the true-up included the following amounts:

2010-11 Forecast True-Up	$ 4,181,114
2010-11 True-Up of the True-Up Balance	($18,152,666)
Emission Allowance (Order No. 32250)	($ 491,989)
DSM Recovery (Order No. 32217)	$ 10,000,000
Net Amount Set for Recovery/(Refund)	($ 4,463,541)
Collection from True-Up Rates	($ 634,702)
Interest	($ 66,926)
True-Up Reconciliation (Credit)	**($ 5,165,169)**

This is the amount recommended for refund by the Company and Staff. When divided by expected sales it produces the reconciliation of the true-up rate credit 0.0392 ¢/kWh. This calculation is shown on Attachment B, line 25.

D. Revenue Sharing

Because the Company proposes to offset the proposed increase in PCA rates with Revenue Sharing credits, Staff reviewed Idaho Power's class allocation of the Revenue Sharing amount. Idaho Power allocated the credit to all customer classes on a uniform percent of revenue basis using forecasted billing determinants and associated class base revenues. Within each customer class the decrease was assigned to the energy rates. This creates a different ¢/kWh rate for each class. Staff accepts this revenue allocation and rate design.

[1] The reconciliation of the true-up is also commonly referred to as the "true-up of the true-up."

PCA AND REVENUE SHARING RATES

The uniform PCA rate surcharge of 0.3367 ¢/kWh is the sum of the three PCA components described above (0.5099 - 0.1340 - 0.0392). This new PCA surcharge rate, shown on Attachment B, line 28, replaces the 0.0629 ¢/kWh credit currently contained within Schedule 55 rates. In this case, the uniform PCA rate is combined with Revenue Sharing credits to arrive at the total PCA rate for each class. Attachment D shows these rates.

Combined PCA and Revenue Sharing Recovery

Attachment E shows the percentage increase in the Combined PCA-Revenue Sharing rates for all Idaho Power customer classes. It includes the uniform PCA increase and the Revenue Sharing decrease. The impact is measured against all billed revenue. The total Staff-recommended increase is $15.9 million which represents an average revenue increase of 1.89%. Increase or decrease percentages vary by customer class. Staff agrees with the Company's proposed combined rates in Schedule 55.

Other PCA Attachments

Staff has included two other attachments that provide summary or historical information concerning the PCA. Staff Attachment F summarizes PCA expense amounts and rate components for this case. The attachment also shows amounts allocated to other jurisdictions and amounts shared with shareholders. Attachment G is a bar graph that shows the amount of each PCA since its inception.

CUSTOMER NOTICE AND PRESS RELEASE

Idaho Power's PCA Application, filed on April 13, 2012, contained both the Customer Notice and Press Release. Staff reviewed both and determined they complied with requirements of Procedural Rule 125.01, IDAPA 31.01.01.125.01. However, the Customer Notice does not comply with requirements of Procedural Rule 125.03, IDAPA 31.01.01.125.03.

Rule 125.03 requires that the information provided in Customer Notices should be "clearly identified, easily understood, and pertain only to the proposed rate change." In the notice sent in this case, five paragraphs are devoted to discussing Public Utility Regulatory Policy Act (PURPA) costs. Although Staff recognizes that PURPA expenses are a major cost component in this year's PCA filing, Idaho Power's discussion of PURPA strays into a discussion of expected future PURPA costs and how those future costs will impact customers in another generic case. Although the case number for the instant PCA case (IPC-E-12-17) is not mentioned in the notice, the case number for the generic PURPA case (GNR-E-11-03) is given. The Customer Notice states that the Commission is accepting public comment in GNR-E-11-03, but there is no statement to that effect with respect to this PCA case.

In the first paragraph under the section labeled "How PURPA Impacts the PCA", the Company compares this year's PURPA-related power supply expenses to those same expenses in 2004. Staff believes a more appropriate comparison between PURPA expenses would be to compare the current PCA case and last year's PCA case. Rule 125.01 requires that the Customer Notice give the overall percentage change from <u>current</u> rates. As one customer noted in his comment, "It seems that Idaho Power is waging an all out war against PURPA projects." In Staff's opinion, the Customer Notice violates Rule 125.03 by addressing and referring to issues that are currently the subject of a different case. At a minimum, the invitation for customers to comment in a separate and distinct case is confusing and misleading.

Another issue of concern is the delay in mailing Notices to customers. Although the Application was filed with the Commission on April 13, the Customer Notice was mailed with Idaho Power's cyclical billings beginning on April 26, 2012 and ending May 24, 2012. Pursuant to the Commission's Notice of Application, customers had until May 15, 2012 to file comments regarding this case. The delay is problematic, particularly in a PCA case that typically has a much shorter timeline than that of general rate cases. More than 100,000 customers would not have received the Customer Notice in their bills until the comment deadline passed.

In response to this concern about the delayed notice, the Company notified Staff on May 4, 2012, that it would issue a "supplemental" Customer Notice in the form of a post card to most of the customers who would not have receive the original Notice in their bills before the comment deadline of May 15, 2012. The affected customers will receive the supplemental Notice via direct mail by May 17, 2012, and will also receive the original Notice in their monthly bills. Staff agrees with the Company that this will provide affected customers with "the opportunity...to submit comments in this case prior to a Commission decision", although the turn-around time for some customers will be quite short. For this reason, Staff encourages the Commission to consider late-filed comments from customers in its deliberations.

The Company indicated to Staff that there were two reasons for the delay in sending the Customer Notice in this case. First, the Company did not want to include more than one Customer Notice in bills; bills including the Notice regarding Case Nos. IPC-E-12-12, IPC-E-12-13 and IPC-E-12-14 were being mailed until April 23, 2012. Second, the Company reports that it takes ten days for the Customer Notices to be printed locally and then shipped to the billing vendor (located in California) that prints, stuffs, and mails the bills. In discussions with Staff, Idaho Power has acknowledged that the processing delay is problematic. The Company is now exploring options on how it can decrease the time it takes to provide customer notification, particularly with respect to cases with abbreviated comment periods such as this one.

Staff recommends that the Company be reminded of its obligation to provide timely notice to customers and be directed to comply with Procedural Rule 125 in future cases.

STAFF RECOMMENDATION

Staff recommends that the Commission approve the Company's Application and the combined PCA/Revenue Sharing rates filed by the Company in proposed Schedule 55.

Staff recommends that the Commission approve a total PCA rate comprised of the uniform ¢/kWh increase of 0.3367 and class-specific rates, as shown on Attachment D, to credit customers for Revenue Sharing amounts. The Staff recommends that these rates be effective June 1, 2012 through May 31, 2013.

Staff recommends that the Company be reminded of its obligation to provide timely notice to customers and be directed to comply with Procedural Rule 125 in future cases.

Respectfully submitted this 15th day of May 2012.

Donald L. Howell, II
Deputy Attorney General

Technical Staff: Keith Hessing
Kathy Stockton
Matt Elam
Marilyn Parker

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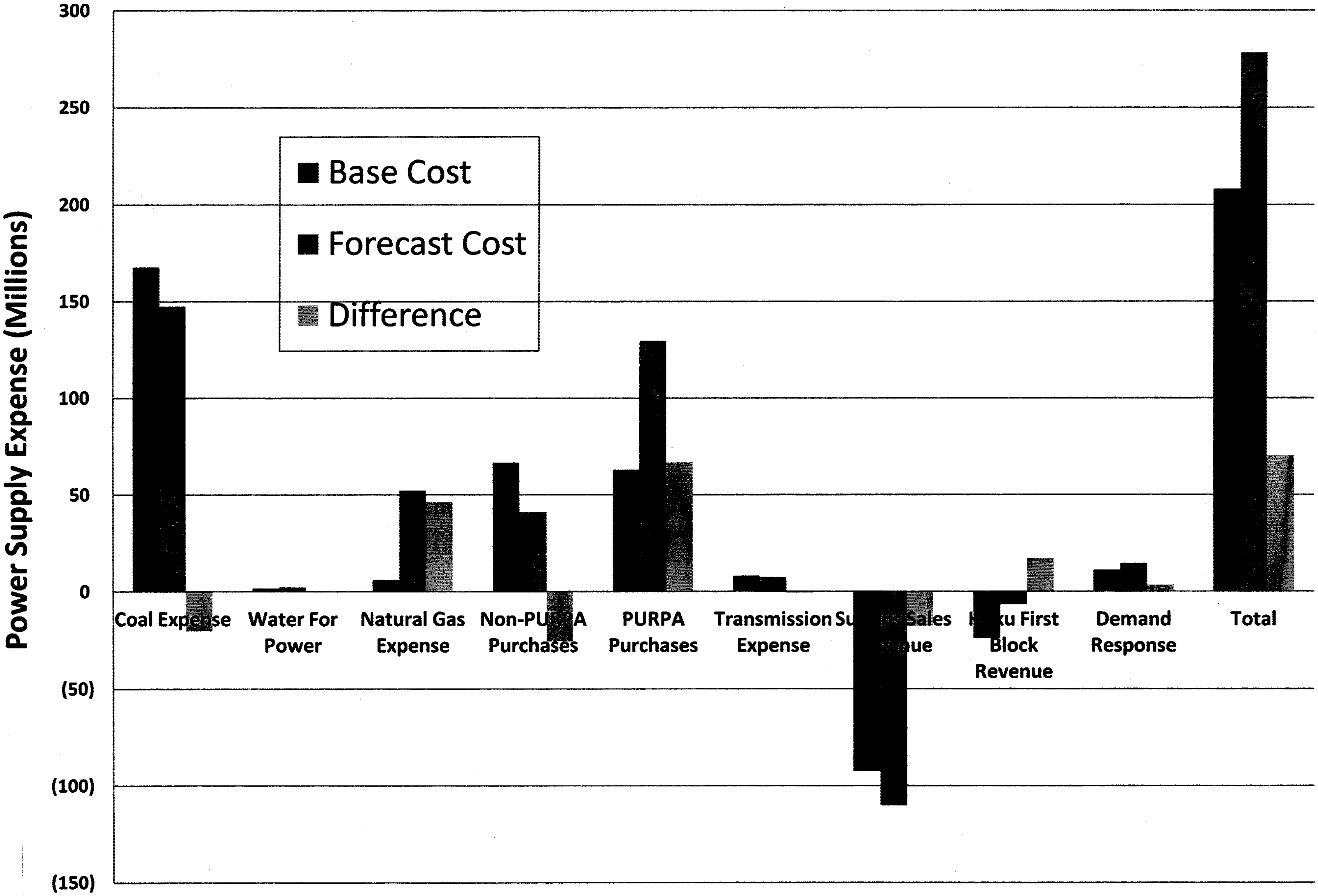
POWER SUPPLY COST PROJECTION

2012 - 2013 PCA Year



Attachment A
Case No. IPC-E-12-17
Staff Comments
05/15/12

2012-2013 PCA - Twentieth Annual
IPC-E-12-17
Staff Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Forecast 2012-2013:**					
2	PCA Expense (95%)	($)	133,997,217	140,832,145		
3	Hoku First Block Revenue	($)		(6,765,150)		
4	Difference	($)		134,066,995	69,778	
5	Sharing Percentage	(%)			0.95	
6	Shared Difference	($)			66,289	
7	Normalized System Firm Sales	(MWH)			13,816,139	
8	Rate for 95 % Items	(¢/kWh)			0.0005	0.0005
9						
10	PCA Expense (100%)	($)	62,851,454	129,590,113	66,738,659	
11	Normalized System Firm Sales	(MWH)			13,816,139	
12	Rate for 100% Items	(¢/kWh)			0.4830	0.4830
13						
14	Demand Response Incentives (100%)	($)	11,252,265	14,723,210	3,470,945	
15	Idaho Jurisdictional Sales	(MWH)			13,172,433	
16		(¢/kWh)			0.0264	0.0264
17						
18	Total Forecast Rate	(¢/kWh)				**0.5099**
19						
20						
21			($)	(MWh)	($/MWh)	(¢/kWh)
22						
23	**True-Up of 2011-2012:**		(17,646,658)	13,172,433	-1.340	**(0.1340)**
24						
25	**True-Up of the True-Up:**		(5,165,169)	13,172,433	-0.3921	**(0.0392)**
26						
27	**PCA Rates:**					
28	PCA Rate Adjustment From Base	(¢/kWh)				**0.3367**
29	PCA Rate Currently in Effect	(¢/kWh)				(0.0629)
30	Difference - Last Year to This Year	(¢/kWh)				0.3996
31						
32	Note: Negative rates and amounts indicate benefits to ratepayers.					
33	The True-Up calculation includes 95% sharing					

TRUE-UP CALCULATIONS FOR 2011 - 2012
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-12-17
(Base Costs are Redistributed)

1			2011	2011	2011	2011	2011	2011	2011
2	DESCRIPTION	Units	APR	MAY	JUN	JUL	AUG	SEPT	OCT
3	**PCA Revenue**								
4	Normalized Idaho Jurisd. Sales	MWh	955,398	960,840	1,115,486	1,354,071	1,414,294	1,295,747	1,035,451
5	Forecast Rate	$/MWh	1.404	1.404	0.445	0.445	0.445	0.445	0.445
6	Revenue	$	1,341,379	1,349,019	496,391	602,562	629,361	576,607	460,776
7									
8	**Load Change Adjustment**								
9	Actual System Firm Load - Adjusted	MWh	1,011,234	1,097,667	1,300,475	1,685,331	1,585,233	1,293,353	1,040,237
10	Normalized Firm Load	MWh	1,085,384	1,282,341	1,412,842	1,685,870	1,594,331	1,225,589	1,100,776
11	Load Change	MWh	(74,150)	(184,674)	(112,367)	(539)	(9,098)	67,764	(60,539)
12	Expense Adjustment	$	1,458,531	3,632,538	2,210,259	10,602	178,958	(1,332,918)	1,190,802
13									
14	**Non-QF PCA**								
15	ACTUAL:								
16	Water Leases	$	0	(514,305)	0	0	1,464,305	1,542,915	0
17	Fuel Expense - Coal	$	6,666,551	4,771,128	5,801,423	10,194,091	13,870,557	11,740,380	11,160,165
18	Fuel Expense - Gas	$	456,072	479,664	1,392,041	1,577,118	3,177,032	485,041	491,516
19	Non-Firm Purchases	$	(264,797)	1,509,941	8,112,353	14,768,259	15,265,932	4,739,731	2,401,316
20	Third Party Transmission	$	337,992	309,423	1,054,471	898,300	860,272	519,502	883,914
21	Surplus Sales	$	(6,221,929)	(6,211,722)	(7,210,510)	(4,788,485)	(7,930,627)	(10,016,187)	(11,818,634)
22	Hoku First Block Energy	$	0	(1,638,183)	(1,692,789)	(1,178,693)	(743,176)	(2,561,825)	(1,692,789)
23	Expense Adjustment	$	1,458,531	3,632,538	2,210,259	10,602	178,958	(1,332,918)	1,190,802
24	Sub-Total	$	2,432,419	2,338,483	9,667,248	21,481,193	26,143,252	5,116,640	2,616,289
25									
26	BASE:								
27	Water for Power (Leases)	$	125,711	124,705	153,090	190,953	204,643	179,325	133,942
28	Fuel Expense - Coal	$	11,529,868	11,437,623	14,041,049	17,513,694	18,769,296	16,447,224	12,284,817
29	Fuel Expense - Gas	$	416,768	413,433	507,539	633,064	678,450	594,515	444,057
30	Non-Firm Purchases	$	4,584,612	4,547,932	5,583,131	6,963,955	7,463,219	6,539,896	4,884,802
31	Third Party Transmission	$	567,976	563,431	691,679	862,746	924,599	810,211	605,165
32	Hoku First Block Energy	$	0	0	0	0	0	0	0
33	Surplus Sales	$	(6,368,731)	(6,317,778)	(7,755,827)	(9,674,005)	(10,367,560)	(9,084,921)	(6,785,741)
34	Sub-Total	$	10,856,204	10,769,346	13,220,661	16,490,407	17,672,647	15,486,250	11,567,042
35									
36	Change From Base	$	(8,423,785)	(8,430,863)	(3,553,413)	4,990,786	8,470,605	(10,369,610)	(8,950,753)
37	Emission Allowance Sales Credit	$	0	0	0	(21,756)	0	0	0
38	Renewable Energy Credit Sales	$	(998,372)	(307,898)	(264,172)	(623,014)	(550,822)	(410,643)	(403,702)
39	Sub-Total	$	(9,422,157)	(8,738,761)	(3,817,585)	4,346,015	7,919,782	(10,780,253)	(9,354,455)
40									
41	Deferral (Shared and Allocated)	$	(8,503,496)	(7,886,732)	(3,445,370)	3,922,279	7,147,603	(9,729,178)	(8,442,396)
42									
43	**Demand Response Incentive Pmts.**								
44	Actual	$	0	0	0	0	0	0	0
45	Base	$	0	0	0	0	0	0	0
46	Change From Base	$	0	0	0	0	0	0	0
47	Deferral	$	0	0	0	0	0	0	0
48									
49	**QF Deferral**								
50	Actual (includes Net Metering)	$	6,235,518	8,098,202	11,029,872	11,225,589	9,677,446	8,186,389	7,619,052
51	Base	$	4,320,756	4,286,188	5,261,808	6,563,163	7,033,693	6,163,509	4,603,670
52	Change From Base	$	1,914,762	3,812,014	5,768,064	4,662,426	2,643,753	2,022,880	3,015,382
53	Deferral (Allocated)	$	1,819,024	3,621,413	5,479,661	4,429,305	2,511,565	1,921,736	2,864,613
54									
55	**Total Deferral** (-6+41+47+53)	$	(8,025,851)	(5,614,338)	1,537,899	7,749,022	9,029,808	(8,384,049)	(6,038,558)
56									
57	**Principal Balances**								
58	Beginning Balance	$	0	(8,025,851)	(13,640,189)	(12,102,290)	(4,353,268)	4,676,540	(3,707,509)
59	Amount Deferred	$	(8,025,851)	(5,614,338)	1,537,899	7,749,022	9,029,808	(8,384,049)	(6,038,558)
60	Ending Balance	$	(8,025,851)	(13,640,189)	(12,102,290)	(4,353,268)	4,676,540	(3,707,509)	(9,746,067)
61									
62	**Interest Balances**								
63	Accrual thru Prior Month	$	0	(7)	1,476	3,044	3,648	(5,786)	(21,278)
64	Interest @ 1% per Year	$	0	1,483	1,569	603	(9,432)	(15,492)	(23,018)
65	Prior Month's Interest Adj.	$	(7)	0	0	0	(1)	(0)	(0)
66	Total Current Month Interest	$	(7)	1,483	1,569	603	(9,434)	(15,492)	(23,018)
67	Interest Accrued to Date	$	(7)	1,476	3,044	3,648	(5,786)	(21,278)	(44,296)
68	**Balance (True-Up & Interest)**	$	(8,025,858)	(13,638,713)	(12,099,245)	(4,349,620)	4,670,754	(3,728,787)	(9,790,363)
69									
70	**True-Up of the True-Up**								
71	True-Up Revenues (Collections)	$	1,601,969	1,526,938	978,989	(420,058)	(479,166)	(458,114)	(381,700)
72									
73	Beginning Balance	$	(18,152,666)	(5,576,831)	(7,600,815)	(8,586,138)	(8,173,235)	(7,700,880)	(7,249,183)
74	Adjustments:								
75	2009-10 PCA Transfer	$	4,181,114	0	0	0	0	0	0
76	Emission Allowance - ON 32250	$	0	(491,989)		0	0	0	0
77	Rider Funds - O.N. 32217	$	10,000,000		0	0	0	0	0
78	Sub-Total	$	(3,971,552)	(6,068,820)	(7,600,815)	(8,586,138)	(8,173,235)	(7,700,880)	(7,249,183)
79	Interest @ 1% per Year	$	(3,310)	(5,057)	(6,334)	(7,155)	(6,811)	(6,417)	(6,041)
80	Revenue Applied to Interest	$	(3,310)	(5,057)	(6,334)	(7,155)	(6,811)	(6,417)	(6,041)
81	Revenue Applied to Balance	$	1,605,278	1,531,996	985,323	(412,903)	(472,355)	(451,697)	(375,659)
82	**True-Up of the True-Up Balance**	$	(5,576,831)	(7,600,815)	(8,586,138)	(8,173,235)	(7,700,880)	(7,249,183)	(6,873,525)

Note: Negative amounts indicate benefit to ratepayers

Attachment C
Case No. IPC-E-12-17
Staff Comments
05/15/12

TRUE-UP CALCULATIONS FOR 2011 - 2012
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-12-17
(Base Costs are Redistributed)

1			2011	2011	2012	2012	2012	
2	DESCRIPTION	Units	NOV	DEC	JAN	FEB	MAR	TOTALS
3	**PCA Revenue**							
4	Normalized Idaho Jurisd. Sales	MWh	956,566	1,081,014	1,177,663	1,101,149	1,004,028	13,451,707
5	Forecast Rate	$/MWh	0.445	0.445	0.445	0.445	0.445	
6	Revenue	$	425,672	481,051	524,060	490,011	446,792	7,823,682
7								
8	**Load Change Adjustment**							
9	Actual System Firm Load - Adjusted	MWh	1,124,273	1,285,108	1,248,576	1,110,751	1,080,667	14,862,905
10	Normalized Firm Load	MWh	1,130,765	1,380,118	1,346,312	1,139,208	1,134,875	15,518,411
11	Load Change	MWh	(6,492)	(95,010)	(97,736)	(28,457)	(54,208)	(655,506)
12	Expense Adjustment	$	127,698	1,868,847	1,774,886	516,779	984,417	12,621,398
13								
14	**Non-QF PCA**							
15	ACTUAL:							
16	Water Leases	$	0	0	0	0	85,000	2,577,915
17	Fuel Expense - Coal	$	12,465,839	15,168,660	12,745,738	10,750,313	7,588,020	122,922,864
18	Fuel Expense - Gas	$	432,515	868,953	443,209	512,867	561,096	10,877,122
19	Non-Firm Purchases	$	3,340,059	3,783,652	3,745,779	2,106,087	2,648,054	62,156,365
20	Third Party Transmission	$	291,183	443,772	308,159	289,909	319,378	6,516,274
21	Surplus Sales	$	(7,165,338)	(7,744,097)	(8,165,168)	(8,830,414)	(10,647,785)	(96,750,895)
22	Hoku First Block Energy	$	(1,640,458)	(1,692,789)	(545,550)	(545,550)	(545,550)	(14,477,351)
23	Expense Adjustment	$	127,698	1,868,847	1,774,886	516,779	984,417	12,621,398
24	Sub-Total	$	7,851,498	12,696,998	10,307,052	4,799,991	992,630	106,443,691
25								
26	BASE:							
27	Water for Power (Leases)	$	125,889	145,752	160,651	147,407	133,303	1,825,371
28	Fuel Expense - Coal	$	11,546,178	13,367,949	14,734,456	13,519,751	12,226,156	167,418,061
29	Fuel Expense - Gas	$	417,357	483,209	532,603	488,696	441,936	6,051,627
30	Non-Firm Purchases	$	4,591,097	5,315,486	5,858,849	5,375,847	4,861,476	66,570,302
31	Third Party Transmission	$	568,779	658,522	725,838	666,000	602,276	8,247,222
32	Hoku First Block Energy	$	0	0	(2,101,561)	(1,928,309)	(1,743,805)	(5,773,675)
33	Surplus Sales	$	(6,377,740)	(7,384,028)	(8,138,843)	(7,467,879)	(6,753,338)	(92,476,391)
34	Sub-Total	$	10,871,560	12,586,890	11,771,993	10,801,513	9,768,004	151,862,517
35								
36	Change From Base	$	(3,020,062)	110,108	(1,464,941)	(6,001,522)	(8,775,375)	(45,418,826)
37	Emission Allowance Sales Credit	$	0	0	(3,446)	0	0	(25,202)
38	Renewable Energy Credit Sales	$	(688,711)	(384,236)	(326,785)	(280,351)	(282,891)	(5,521,597)
39	Sub-Total		(3,708,773)	(274,128)	(1,795,171)	(6,281,873)	(9,058,266)	(50,965,625)
40								
41	Deferral (Shared and Allocated)	$	(3,347,167)	(247,401)	(1,620,142)	(5,669,391)	(8,175,085)	(45,996,477)
42								
43	Demand Response Incentive Pmts.							
44	Actual	$	0	0	0	0	0	0
45	Base	$	0	0	988,540	907,045	820,257	2,715,842
46	Change From Base	$	0	0	(988,540)	(907,045)	(820,257)	(2,715,842)
47	Deferral	$	0	0	(988,540)	(907,045)	(820,257)	(2,715,842)
48								
49	**QF Deferral**							
50	Actual (includes Net Metering)	$	9,540,246	7,374,112	9,614,927	8,156,684	7,088,958	103,846,995
51	Base	$	4,326,868	5,009,567	5,521,658	5,066,454	4,581,686	62,739,020
52	Change From Base	$	5,213,378	2,364,545	4,093,269	3,090,230	2,507,272	41,107,975
53	Deferral (Allocated)	$	4,952,709	2,246,318	3,888,605	2,935,718	2,381,908	39,052,576
54								
55	**Total Deferral** (-6+41+47+53)	$	1,179,870	1,517,866	755,863	(4,130,729)	(7,060,226)	(17,483,424)
56								
57	**Principal Balances**							
58	Beginning Balance	$	(9,746,067)	(8,566,198)	(7,048,332)	(6,292,469)	(10,423,198)	
59	Amount Deferred	$	1,179,870	1,517,866	755,863	(4,130,729)	(7,060,226)	(17,483,424)
60	Ending Balance	$	(8,566,198)	(7,048,332)	(6,292,469)	(10,423,198)	(17,483,424)	
61								
62	**Interest Balances**							
63	Accrual thru Prior Month	$	(44,296)	(70,608)	(97,900)	(125,294)	(147,241)	
64	Interest @ 1% per Year	$	(26,312)	(27,299)	(27,394)	(21,947)	(15,993)	(163,232)
65	Prior Month's Interest Adj.	$	0	6	0	0	0	(3)
66	Total Current Month Interest	$	(26,312)	(27,292)	(27,394)	(21,947)	(15,993)	(163,234)
67	Interest Accrued to Date	$	(70,608)	(97,900)	(125,294)	(147,241)	(163,234)	
68	**Balance (True-Up & Interest)**	$	(8,636,806)	(7,146,232)	(6,417,764)	(10,570,439)	(17,646,658)	**(17,646,658)**
69								
70	**True-Up of the True-Up**							
71	True-Up Revenues (Collections)	$	(330,805)	(352,881)	(363,912)	(352,417)	(334,141)	634,702
72								
73	Beginning Balance	$	(6,873,525)	(6,548,448)	(6,201,024)	(5,842,279)	(5,494,731)	(18,152,666)
74	Adjustments:							
75	2009-10 PCA Transfer	$	0	0	0	0	0	4,181,114
76	Emission Allowance - ON 32250	$	0	0	0	0	0	(491,989)
77	Rider Funds - O.N. 32217	$	0	0	0	0	0	10,000,000
78	Sub-Total	$	(6,873,525)	(6,548,448)	(6,201,024)	(5,842,279)	(5,494,731)	(4,463,541)
79	Interest @ 1% per Year	$	(5,728)	(5,457)	(5,168)	(4,869)	(4,579)	
80	Revenue Applied to Interest	$	(5,728)	(5,457)	(5,168)	(4,869)	(4,579)	(66,926)
81	Revenue Applied to Balance	$	(325,077)	(347,424)	(358,744)	(347,549)	(329,562)	701,628
82	**True-Up of the True-Up Balance**	$	(6,548,448)	(6,201,024)	(5,842,279)	(5,494,731)	(5,165,169)	**(5,165,169)**

Note: Negative amounts indicate benefit to ratepayers

Attachment C
Case No. IPC-E-12-17
Staff Comments
05/15/12 Page 2 of 2

Idaho Power Company
Calculation of PCA Rate by Class
State of Idaho
Case No. IPC-E-12-17
Staff Proposal

Line No		Rate Schedule No	(1) Current Billed Revenue	(2) Allocated Revenue Sharing Benefit	(3) Test Year Billed kWh	(4) Revenue Sharing Rate Cents per kWh	(5) Uniform PCA Rate Cents per kWh	(6) Total Combined PCA Rate Cents per kWh
1	Residential Service	1,4,5	$397,700,569	($12,600,731)	4,896,272,827	(0.2574)	0.3367	0.0793
2	Master Metered Mobile Home Park	3	$381,220	($12,062)	4,942,681	(0.2440)	0.3367	0.0927
3	Small General Service	7	$14,990,300	($474,246)	144,888,296	(0.3273)	0.3367	0.0094
4	Large General Service - Secondary	9S	$176,385,854	($5,732,224)	3,056,964,925	(0.1875)	0.3367	0.1492
5	Large General Service - Primary	9P	$20,237,805	($659,119)	420,423,939	(0.1568)	0.3367	0.1799
6	Large General Service - Transmission	9T	$130,585	($4,253)	2,712,595	(0.1568)	0.3367	0.1799
7	Dusk to Dawn Lighting	15	$1,173,934	($37,871)	6,481,376	(0.5843)	0.3367	(0.2476)
8	Large Power Service - Secondary	19S	$319,273	($10,399)	6,678,959	(0.1557)	0.3367	0.1810
9	Large Power Service - Primary	19P	$81,670,938	($2,664,599)	1,930,039,445	(0.1381)	0.3367	0.1986
10	Large Power Service - Transmission	19T	$1,670,079	($54,541)	41,905,243	(0.1302)	0.3367	0.2065
11	Agricultural Irrigation Service	24	$109,785,557	($3,563,932)	1,720,204,410	(0.2072)	0.3367	0.1295
12	Unmetered General Service	40	$1,096,245	($35,561)	15,807,753	(0.2250)	0.3367	0.1117
13	Street Lighting	41	$2,959,897	($95,628)	23,165,568	(0.4128)	0.3367	(0.0761)
14	Traffic Control Lighting	42	$142,887	($4,654)	2,981,282	(0.1561)	0.3367	0.1806
15	Total Uniform Tariffs		$808,645,142	($25,949,819)	12,273,469,299			
16	Special Contracts:							
17	Micron	26	$17,176,418	($561,642)	451,138,622	N/A	0.3367	0.3367
18	J R Simplot	29	$6,727,934	($220,347)	203,558,197	N/A	0.3367	0.3367
19	DOE	30	$8,393,976	($274,869)	244,266,665	N/A	0.3367	0.3367
20	Hoku	32	$2,835,760	($92,221)	0	N/A	0.3367	0.3367
21	Total Special Contracts		$35,134,087	($1,149,078)	898,963,484			
22	Total Idaho Jurisdiction		$843,779,229	($27,098,897)	13,172,432,783			

Combined Effect of All Filings
Staff Proposal

Present Billed Rates to 6/1/2012 Billed Rates (PCA & Revenue Sharing)

Line No	Tariff Description	(1) Rate Sch. No.	(2) Average Number of Customers	(3) Normalized Energy (kWh)	(4) Current Billed Revenue	(5) Billed Revenue Adjustments	(6) Proposed Billed Revenue	(7) Average ¢/kWh	(8) Percent Change
1	Uniform Tariff Rates:								
2	Residential Service	1	399,329	4,896,272,827	$397,700,569	$ 2,469,997	$400,170,566	8.173	0.62%
3	Master Metered Mobile Home Park	3	23	4,942,681	$381,220	$ 3,152	$384,372	7.777	0.83%
4	Residential Service Energy Watch	4	0	0	$0	$0	$0	0	N/A
5	Residential Service Time-of-Day	5	0	0	$0	$0	$0	0	N/A
6	Small General Service	7	28,165	144,888,296	$14,990,300	$ (64,502)	$14,925,798	10.302	-0.43%
7	Large General Service	9	31,614	3,480,101,459	$196,754,244	$ 5,229,661	$201,983,905	5.804	2.66%
8	Dusk to Dawn Lighting	15	0	6,481,376	$1,173,934	$ (25,478)	$1,148,456	17.719	-2.17%
9	Large Power Service	19	116	1,978,623,647	$83,660,290	$ 4,204,442	$87,864,732	4.441	5.03%
10	Agricultural Irrigation Service	24	16,642	1,720,204,410	$109,785,557	$ 2,031,893	$111,817,450	6.500	1.85%
11	Unmetered General Service	40	2,030	15,807,753	$1,096,245	$ 14,898	$1,111,143	7.029	1.36%
12	Street Lighting	41	361	23,165,568	$2,959,897	$ (37,019)	$2,922,878	12.617	-1.25%
13	Traffic Control Lighting	42	397	2,981,282	$142,887	$ 5,599	$148,486	4.981	3.92%
14	*Total Uniform Tariffs*		478,677	12,273,469,299	$808,645,142	$ 13,832,644	$822,477,786	6.701	1.71%
15									
16	Special Contracts:								
17	Micron	26	1	451,138,622	$17,176,418	$ 1,051,179	$18,227,597	4.040	6.12%
18	J R Simplot	29	1	203,558,197	$6,727,934	$ 512,666	$7,240,600	3.557	7.62%
19	DOE	30	1	244,266,665	$8,393,976	$ 605,712	$8,999,688	3.684	7.22%
20	Hoku	32	1	0	$2,835,760	$ (92,221)	$2,743,539	0.000	-3.25%
21	*Total Special Contracts*		4	898,963,484	$35,134,087	$ 2,077,337	$37,211,424	4.139	5.91%
22									
23									
24	***Total Idaho Retail Sales***		478,681	13,172,432,783	$843,779,229	$ 15,909,980	$859,689,210	6.526	1.89%

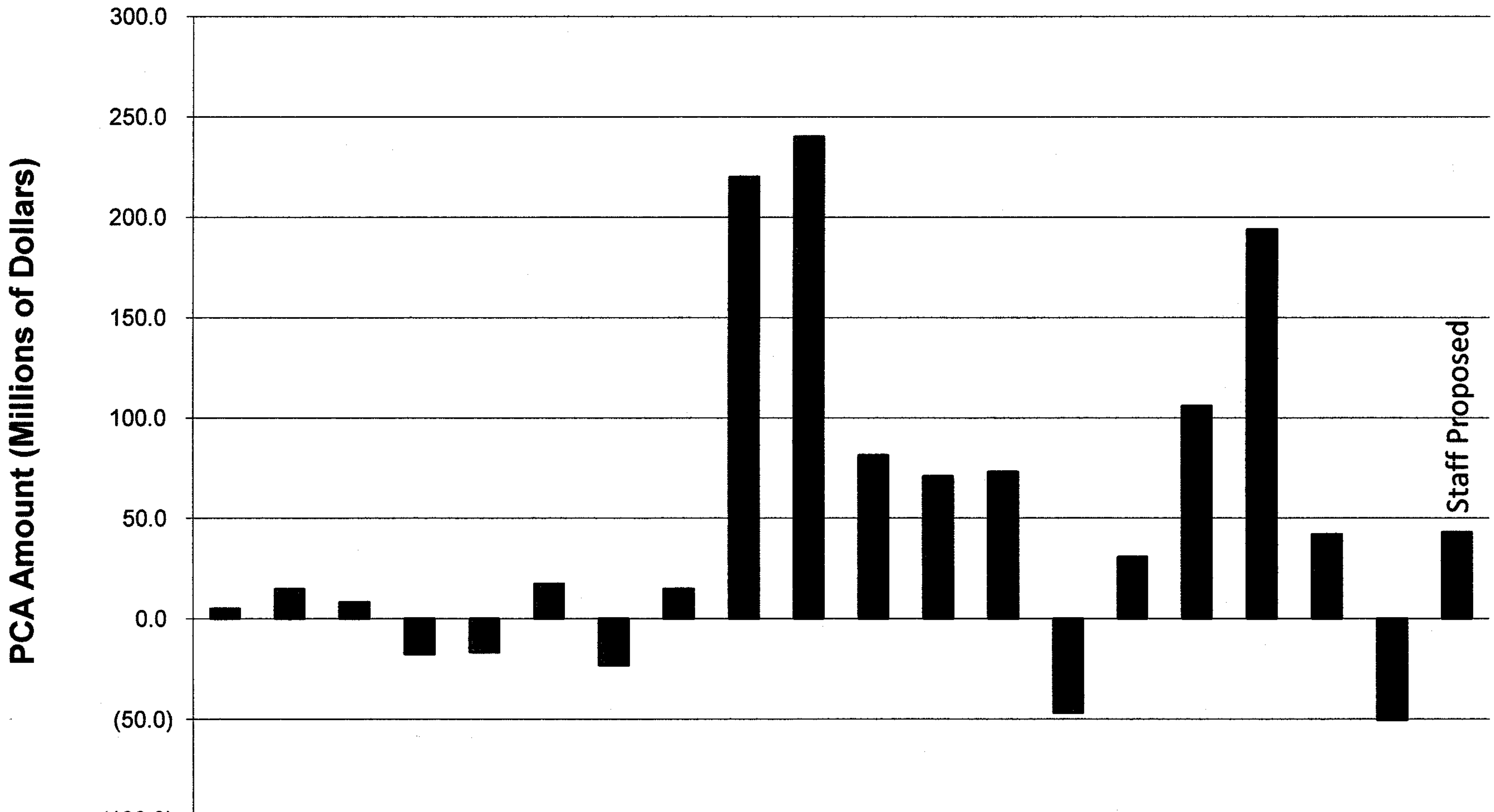
Power Supply Cost Summary
Case No. IPC-E-12-17
Base Costs are Redistributed

Description	Projection or Actual ($)	Base ($)	Difference or Initial Amount ($)	Allocated to Other Jurisdictions ($)	Shared with Shareholders ($)	Idaho Customer Revenue Requirement ($)	**Idaho PCA Rates (¢/kWh)**
Forecast or Projection (2012-2013)	Projection	Base	Difference				
Acct. 501 - Coal	147,503,921	167,718,084	(20,214,163)	(1,010,708)	(960,173)	(18,243,282)	
Acct. 536 - Water for Power	2,521,000	1,828,640	692,360	34,618	32,887	624,855	
Acct. 547 - Natural Gas	52,250,517	6,062,472	46,188,045	2,309,402	2,193,932	41,684,711	
Acct. 555 - Purchased Power (Non- PURPA)	41,169,588	66,689,601	(25,520,013)	(1,276,001)	(1,212,201)	(23,031,812)	
Acct. 565 - Transmission Wheeling	7,554,520	8,262,000	(707,480)	(35,374)	(33,605)	(638,501)	
Acct. 447 - Opportunity Sales Revenues	(110,167,401)	(92,642,114)	(17,525,287)	(876,264)	(832,451)	(15,816,572)	
Acct. 442 - Hoku First Block Energy Revenue	(6,765,150)	(23,921,466)	17,156,316	857,816	814,925	15,483,575	0.0005
Acct. 555 - Purchased Power (PURPA)	129,590,113	62,851,454	66,738,659	3,336,933	0	63,401,726	0.4830
Demand Response Incentive Payments	14,723,210	11,252,265	3,470,945	0	0	3,470,945	0.0264
Sub-Total	278,380,318	208,100,936	70,279,382	3,340,422	3,314	66,935,646	**0.5099**
True Up (2011-2012)	Actual	Base	Difference				
Revenue from Forecast Rate	7,823,682	0	7,823,682	0	0	7,823,682	
Load Change Adjustment	12,621,398	0	12,621,398	631,070	599,516	11,390,811	
Acct. 501 - Coal	122,922,864	167,418,061	(44,495,197)	(2,224,760)	(2,113,522)	(40,156,915)	
Acct. 536 - Water for Power	2,577,915	1,825,371	752,544	37,627	35,746	679,171	
Acct. 547 - Natural Gas	10,877,122	6,051,627	4,825,495	241,275	229,211	4,355,009	
Acct. 555 - Purchased Power (Non- PURPA)	62,156,365	66,570,302	(4,413,937)	(220,697)	(209,662)	(3,983,578)	
Acct. 565 - Transmission Wheeling	6,516,274	8,247,222	(1,730,948)	(86,547)	(82,220)	(1,562,180)	
Acct. 447 - Opportunity Sales Revenues	(96,750,895)	(92,476,391)	(4,274,504)	(213,725)	(203,039)	(3,857,740)	
Acct. 442 - Hoku First Block Energy Revenue	(14,477,351)	(5,773,675)	(8,703,676)	(435,184)	(413,425)	(7,855,068)	
Acct. 555 - Purchased Power (PURPA)	103,846,995	62,739,020	41,107,975	2,055,399	0	39,052,576	
Emission Allowance Sales Credit	(25,202)	0	(25,202)	(1,260)	(1,197)	(22,745)	
REC Sales	(5,521,597)	0	(5,521,597)	(276,080)	(262,276)	(4,983,241)	
Interest During Deferral Period	(163,234)	0	(163,234)	0	0	(163,234)	
Demand Response Incentive Payments	0	2,715,842	(2,715,842)	0	0	(2,715,842)	
Sub-Total	196,756,971	217,317,379	(20,560,408)	(492,883)	(2,420,867)	(17,646,658)	**(0.1340)**
True Up of the True Up (Reconciliation of the True Up)			Initial Amount				
Unrecovered True Up of the True Up Amount Carried Forward			(18,152,666)			(18,152,666)	
Other Limited Term Adjustments:							
PCA True Up Amount Transferred			4,181,114			4,181,114	
Emission Allowances - ON 32250			(491,989)			(491,989)	
DSM Rider Funds - ON 32217			10,000,000			10,000,000	
Interest During Amortization			(66,926)			(66,926)	
Revenue from True Up & True Up of the True Up Rates			(634,702)			(634,702)	
Sub-Total			(5,165,169)	0	0	(5,165,169)	**(0.0392)**
Total Power Cost Adjustment (PCA)							**0.3367**

Attachment F
Case No. IPC-E-12-17
Staff Comments
05/15/12

HISTORY OF PCA AMOUNTS

2012 - 2013 PCA Year



	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
■PCA Amounts	4.9	14.7	8.1	(17.6)	(16.7)	17.3	(23.2)	14.8	220.2	240.2	81.3	70.8	73.1	(46.8)	30.7	106.0	194.0	41.9	(50.4)	43.0

PCA Year

Attachment G
Case No. IPC-E-12-17
Staff Comments
05/15/12

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 15TH DAY OF MAY 2012, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-12-17, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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Jo Nelson
SECRETARY