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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, 2010 THROUGH MAY 31, 2011.	**CASE NO. IPC-E-10-12** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Weldon B. Stutzman, Deputy Attorney General, and in response to the Notice of Application and Notice of Modified Procedure issued in Order No. 31064 on April 27, 2010, submits the following comments.

BACKGROUND

On April 15, 2010, Idaho Power filed an Application to implement its Power Cost Adjustment (PCA) rates effective June 1, 2010 through May 31, 2011 and to change base rates. The Application states that the proposed PCA computation results from a Stipulation approved by the Commission in Order No. 30978, Case No. IPC-E-09-30 issued January 13, 2010. That Stipulation provides for a sharing between customers and Company shareholders of any PCA revenue reduction that results from this case. The Stipulation provides that PCA rates will be reduced by the full calculated amount and that base rates will be increased in an amount that partially offsets the PCA decrease. Idaho Power's filing calculates the PCA revenue reduction to be approximately $146.7 million and the base rate increase to be approximately $88.7 million. The net customer benefit is approximately $58 million which produces an average decrease in rates of 6.47%. However, due to the fact that PCA rate changes are spread on an equal cents per kWh basis, some customer class rate changes vary widely from the average percentage.

IDAHO POWER COMPANY'S FILING

The Power Cost Adjustment (PCA) Mechanism

In general terms, the PCA is an annual symmetrical rate adjustment mechanism that recovers abnormally high power supply costs from customers or credits customers with savings when power supply costs are abnormally low. The PCA has three components that combine to produce an annual PCA rate. The first component is the Forecast or Projection. The Projection is an estimate of the difference between normal power supply costs embedded in base rates and the coming year's power supply costs. The Company uses its Operating Plan to estimate the coming year's power supply costs. The PCA amount is converted to a rate by dividing by energy sales. In this filing the Company calculates above normal power supply costs of $87.6 million relative to power supply costs contained in current base rates and above normal power supply costs of $20.9 million relative to power supply costs contained in proposed base rates. After PCA sharing, these two amounts produce rates to recover projected above normal power supply costs of 0.5814 ¢/kWh and 0.1404 ¢/kWh respectively. The Company proposes to update base rates and use the 0.1404 ¢/kWh as the new PCA projection rate component.

The second PCA component is the true-up. The true-up captures the difference between the previous year's projection and actual power supply costs. If the Projection proved to be 100 percent accurate, there would be no true-up. The true-up amount is converted to a rate by dividing by projected energy sales. Idaho Power calculates this amount and rate to be $11,963,777 and 0.0888 ¢/kWh.

The third PCA component is the true-up of the true-up or reconciliation of the previous year's true-up. This component calculates the amount of the unrecovered true-up. The previous year's true-up amount is not precisely recovered due to actual sales being different from the previous year's projected sales and due to the two-month lag between the end of the PCA accounting year and the implementation of new PCA rates. Idaho Power calculates the reconciliation of the true-up amount and rate to be $11,284,407 and 0.0838 ¢/kWh.

The combination of the three components produces a 2010/2011 PCA rate of 0.3130 ¢/kWh (0.1404 + 0.0888 + 0.0838). The use of the lower projection rate of 0.1404 ¢/kWh assumes that Base Rates are updated in this case to include a new level of normalized power supply costs.

The Base Rate Increase

As previously mentioned the Stipulation accepted by the Commission in Order No. 30978, Case No. IPC-E-09-30, provides for a base rate increase to include, among other things, increases in normal Power Supply Costs that have occurred since the Company's last general rate case. The Company's filing includes an increase in base rates of approximately $88.7 million.

Case No. IPC-E-10-01, Order No. 31042, carried over to this case the issue of the appropriate level of Bridger coal costs to be included in base power supply costs and, therefore, in base rates. The amount of base level Bridger coal costs included in the Company's calculations in this case is the level the Company proposed in the previous case.

The Combined PCA and Base Rate Impact

The combined impact of the PCA rate decrease proposed by the Company and the base rate increase proposed by the Company is shown on page 1 of Company Exhibit No. 2. The disparity in customer class rate change percentages results from the equal cents per kWh rate spread of the PCA decrease. High load factor customers get larger percentage decreases when PCA rates are reduced just as they received larger percentage increases when PCA rates go up. PCA percentage increases and decreases are relatively small for smaller, generally lower load factor customers. In this particular case two lighting classes, Schedule 15 – Dusk to Dawn Lighting and Schedule 41 – Street Lighting, are proposed to receive net increases because the equal percentage base rate increase is larger to them than the equal cents per kWh decrease from the PCA.

STAFF AUDIT AND ANALYSIS

A. The PCA Forecast or Projection

As previously discussed, the projection is prepared using the Company's most recent Operating Plan. The Operating Plan incorporates the most current information available in each update. An account by account breakdown of the Company's power supply forecast proposal is shown on Attachment A to these comments. The chart shows the amounts included in Base Rates, Forecast amounts and the Difference. Account 555 – PURPA Purchases is shown separately from other Account 555 Purchases because differences in PURPA Purchases are not shared, the entire difference is passed on to customers.

Attachment B shows the Company (page 1) and Staff (page 2) PCA rate calculation. Page 1, lines 1 through 15 shows the calculation of the Forecast Rate proposed by the Company. Line 3 shows the forecast offset due to expected Hoku first block revenues. Line 4 shows an expected reduction in power supply costs associated with the sale of Renewable Energy Credits (REC) and SO2 Emission Allowances. Line 6 shows the customer sharing percentage that is applied to all power supply cost differences, except the difference in PURPA costs. Line 9, Column (g), shows the forecast rate excluding the portion of the forecast rate associated with the expected PURPA cost difference. This rate is 0.1319 ¢/kWh. Lines 11 through 13 show the calculation of the portion of the Forecast Rate associated with the expected difference in PURPA costs. This rate is 0.0085 ¢/kWh. The two parts of the forecast rate combine to produce the forecast rate shown on line 15, 0.1404 ¢/kWh. Among other things, this rate reflects water conditions that are expected to be well below normal. Under this forecast methodology, Idaho Power does its own water forecast; however, the Northwest River Forecast Center expects April through July Brownlee Reservoir inflow to be 52% of normal. Although this year's PCA rate is proposed to be substantially lower than last year's PCA rate, power supply costs are projected to be approximately $20 million above normal.

The Staff has reviewed the Company's Operating Plan based Forecast and believes that it is reasonable. The forecast will not be perfect but the difference between forecast and actual is trued-up in the following year's PCA.

B. The PCA True-Up

The PCA true-up captures the difference between actual and projected power supply costs experienced in the past year. With some adjustments, this difference becomes the PCA true-up deferral balance. This deferral balance divided by expected sales is known as the PCA true-up rate component.

Lines 4 through 78 of Exhibit No. 1 to Idaho Power witness Scott Wright's testimony calculate the true-up deferral amount. Attachment C to these comments is Staff's verification of the Company's true-up deferral calculations. In Case No. IPC-E-08-19, Order No. 30715, the Commission authorized Idaho Power to redistribute monthly base power supply costs in a specific manner to meet some particular needs of the Company. The monthly redistribution was to leave annual base power supply costs unchanged, which it has. However, the redistribution caused $215,027 of additional interest to be deferred. Attachment D is Staff's calculation of the true-up deferral amount when base power supply costs are not redistributed. Line 60 in both Attachments shows accumulated true-up interest. Attachment C interest is $265,945 and Attachment D interest is $50,918. In Order No. 30715 when discussing "Forecast and Expense Distribution" the Commission said:

> The remaining issues addressed in the Stipulation do not affect the overall PCA cost responsibility between customers and shareholders.

Clearly the Commission envisioned no cost difference as a result of the redistribution. Therefore, Staff proposes that the interest difference be removed from the true-up balance proposed by the Company. The Staff shows the removal of the interest difference on Attachment B, page 2, line 21, as part of Staff's true-up rate calculation.

This year's true-up calculation includes a negative Load Growth adjustment of approximately $23.7 million. Actual loads during the true-up year were below normal loads in 10 of 12 months. The total below normal load was 889,235 MWh. This represents a 5.6% load decline. The adjustment is the product of the negative load growth and the load growth adjustment rate (LGAR) of 26.63 $/MWh. The LGAR is composed of the variable and 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 lost fixed production costs and makes the Company whole with respect to variable production costs. The result is that $21.3 million (after Jurisdictional Allocation and PCA sharing) has been added to the deferral balance for recovery from customers in this year's PCA. This amounts to 51% of the Company's request to recover approximately $41.9 million in above normal costs. Negative monthly load growth has previously been included in PCA calculations and is part of the approved calculation methodology. Nevertheless, Staff is currently reviewing the justification for the adjustment when load declines, and plans to meet with the Company to discuss possible load growth adjustment modification. Staff is recommending no change to the load growth adjustment amounts or methodology in this case.

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. 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 expenses, green tag Sales Credit (RECs), and Qualifying Facilities expenses. Staff also examined the Emission Allowance Sales Credit passed onto customers in the true-up of the true-up, and the Risk Management operating plan.

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

1. Water Leases. The Company leases water for the production of 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 refund to customers. This year's PCA deferral balance includes actual water lease expenses of $2,205,906 and the amount included in base rates is $67,519, with the difference of $2,138,387 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.

2. Fuel Expense – Coal. A large portion of Idaho Power's electricity comes from thermal power produced from coal plants. The three coal plants that Idaho Power owns an interest in are Bridger, Valmy and Boardman. The increase or decrease in the coal expense from base rates is included in the PCA for recovery from or refund to customers. For the audit period of April 2009 to March 2010, the total coal expense for all plants in operation is $128,504,371. The total coal expense included in base rates is $133,454,723. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $4,950,352. This reduction in coal costs from base costs is a benefit to customers and is subject to jurisdictional allocation and sharing.

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

For the audit period of April 2009 to March 2010 the total variable gas and gas transportation expense for both complexes was $18,420,326. The total gas and gas transportation expense included in base rates is $6,125,180. The increase or decrease in gas expense from base rates is included in the PCA for recovery from or refund to customers. In this year's PCA deferral balance, the additional gas expense that is included for future recovery from customers is $12,295,146 and is subject to jurisdictional allocation and sharing.

4. Power Sales and Purchases. Staff reviewed the power purchases and sales in conjunction with the Company's Risk Management Operating Plan. Staff analysis 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, 2010, the Company sold surplus power totaling $94,357,434. The total surplus sales included in base rates is $116,568,567.

The increase or decrease in the power sales from base rates is included in the PCA for recovery from or refund to customers and is subject to jurisdictional allocation and sharing. Actual surplus sales were less than base amounts by $22,221,133. This difference is a reduction of revenues to the detriment of customers and is subject to jurisdictional allocation and sharing.

b. Power Purchases. During the PCA year ending March 31, 2010, the Company made market purchases, excluding PURPA contracts. The actual amount is $83,632,863. The total power purchases included in base rates is $57,231,921. Actual purchased power amounts exceed base amounts by $26,400,942. This difference is a cost to customers and is subject to jurisdictional allocation and sharing.

5. Actual Qualifying Facilities Purchases Including Net Metering and Raft River. 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 Part 292 of the Federal Energy Regulatory Commission's Regulations (18 C.F.R. Part 292), and which has obtained certification of its QF status. There are two types of QFs – cogeneration facilities and small power production facilities. Qualifying Facilities are sometimes referred to as cogeneration/small power producers or by the acronym CSPP.

A Cogeneration Facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, residential or institutional purposes, and otherwise meets the requirements of 18 C.F.R. §§ 292.203(b) and 292.205 for operation, efficiency and use of energy output.

A Small Power Production Facility is a generating facility whose primary energy source is renewable (hydro, wind, solar, etc.), biomass, waste, or geothermal resources, and that otherwise meets the requirements of 18 C.F.R. §§ 292.203(a), 292.203(c) and 292.204. Small power production facilities are limited in size to 80 MW, with the exception of certain types of facilities certified prior to 1995 and designated as "eligible" under section 3(17)(E) of the Federal Power Act (FPA) (15 U.S.C. § 796(17)(E), which have no size limitation.

For the audit period of April 2009 through March 2010 the actual QF expense is $64,344,768. The QF expense included in base rates is $63,269,889. The increase or decrease in the QF expense from base rates is included in the PCA for recovery from or refund to customers. In this year's PCA deferral balance, the actual QF expense was more than the base QF by $1,074,879. This amount is a cost to customers and increases the PCA deferral balance. PURPA contracts are not currently subject to sharing. They are subject to jurisdictional allocation.

6. Third Party Transmission. In Order No. 30715, Case No. IPC-E-08-19, the Commission found that third-party transmission costs that are incurred in conjunction with market purchases and sales should be tracked through the PCA like other variable power supply costs, and that including the 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 2009 to March 2010, the actual third party transmission expense is $6,692,114. The Third Party Transmission expense included in base rates is $10,469,726. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $3,777,612. 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. 31042, Case No. IPC-E-10-01, the Commission established the base level for net power supply for 2010. In this Order, the Commission accepted the Staff's recommendation that the Hoku expenses be captured in the PCA, and not in base rates for 2010. Therefore, the actual costs are included in the PCA deferral, and there are not corresponding base level amounts of Hoku expenses. In this deferral balance, there is a credit of $611 included in the deferral balance. This represents a benefit to customers and is subject to jurisdictional allocation and sharing.

8. Green Tag Sales Credit. In Order No. 30818, Case No. IPC-E-08-24, the Commission ordered that green tag sales benefits flow to customers, subject to jurisdictional allocations and sharing. The amount included in the deferral balance is $665,788. This is a benefit to customers.

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

Deferral Balance Components

Load Growth Adjustment	$23,680,328
Water Leases	$2,138,387
Fuel Expense – Coal	$ (4,950,352)
Fuel Expense – Gas	$12,295,146
Surplus Sales	$22,211,133
Non-Firm Purchases	$26,400,942
Third Party Transmission	$ (3,777,612)
Hoku Energy	$(611)
Subtotal	$77,997,362
Subtotal (After Jurisdictional Allocations and Sharing)	$69,644,815

Qualifying Facilities (After Jurisdictional Allocations)	$1,018,985
Total all Expense Items	$70,663,800
Less Jurisdictional Forecast Revenue	$58,965,969
Deferral Balance	$11,697,831
Staff Interest on the Deferral Balance	$50,918
Deferral Balance (True-Up)	**$11,748,749**

The Company-proposed true-up rate is 0.0888 ¢/kWh as shown on Staff Attachment B, page 1, line 20. The Staff-proposed true-up rate is 0.0872 ¢/kWh as shown on Staff Attachment B, page 2, line 20. The only difference is Staff's true-up interest adjustment.

C. The PCA True-Up of the True-Up

The PCA reconciliation of the true-up 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 amount represents the under or over recovery of the true-up amount from the previous year due to a different amount of kWh being sold than was anticipated in the rate design and the fact that the true-up period included only 10 months with the true-up rate in place. The true-up of the true-up is a benefit to both the Company and customers because any true-up over-collection is returned to customers, and any true-up under-collection is recovered by the Company.

Included in this year's true-up of the true-up is the benefit to customers from the 2008-2009 SO2 Emission sales. Per Order No. 30790, the Company recorded the proceeds from the sale of the 2008-2009 SO2 credits in the current year's PCA. The Idaho Jurisdictional portion of the SO2 allowance proceeds, including interest but net of tax were recorded in the PCA deferral account and included in the true-up of the true-up section in the months of April 2009 and June 2009. The total system SO2 amount is $5,229,875 plus accrued interest. The Idaho jurisdictional amount after jurisdictional allocation and sharing is $4,591,632. This is a benefit to customers.

Last year's unrecovered true-up amount to be recovered in this case is approximately $11.3 million. This amount is calculated on Company Exhibit No. 1, lines 80 through 97. The Staff calculates the same amount on Attachment D, page 2, lines 64 through 76. The true-up of the true-up rate is calculated on Attachment B, page 1 (Company Case) or page 2 (Staff Case), line 24, to be 0.0838 ¢/kWh. The Staff and Company calculate the same rate for the true-up of the true-up.

PCA RATES

The Staff's calculated PCA rate of 0.3114 ¢/kWh is the sum of the three components described above (0.1404 + 0.0872 + 0.0838 = 0.3114). This rate is shown on Attachment B, page 2, line 27. This rate is well below the 1.4022 ¢/kWh currently in place. This PCA rate decrease is not a refund of below normal power costs but simply a lower surcharge than the surcharge currently in place. Attachment E, page 1, shows the impact on all Idaho Power customer classes of the PCA rate decrease.

Base Rates

A. Bridger Coal Costs

The Settlement Stipulation accepted by the Commission in Case No. IPC-E-09-30, Order No. 30978, provided for an increase in base rates if PCA rates were reduced in this filing. The magnitude of the base rate increase includes, as a component, normal power supply costs. Normal power supply costs were identified in Case No. IPC-E-10-01, Order No. 31042, as approximately $63.7 million more than are included in present base rates. The one unresolved issue from that case that could affect this amount was the cost of Bridger coal. The Bridger coal cost issue was carried over to this case to obtain a timely decision in the cited case and to allow other pertinent information to be made available. That information is now available.

The Bridger coal cost issue has come up because the coal supply contract with Bridger Coal Company recently expired and coal costs under the new contract are significantly higher than they were under the old contract. Also, Bridger Coal Company is a wholly-owned subsidiary of Idaho Power Company and PacifiCorp who own the Jim Bridger power plant. The concern is whether customers are getting the coal prices they should given the fact that the contract is with an affiliate. When a regulated utility contracts with an unregulated affiliate, it is common practice to reflect in rates the lower of the actual cost or the comparable market cost. The issue was first raised in Oregon PUC Docket No. UE 214 where direct and rebuttal testimony have been filed and discovery requests have been asked and answered. That case continues and will be decided later in the year.

The IPUC Staff has reviewed the new contract, testimony and production requests in the Oregon case, a white paper prepared by Idaho Power Company to address the issues (including the lower of cost or market issue), responses to production requests asked by Idaho Staff and Intervenors and Idaho Power witness Tom Harvey's testimony in this case. The Staff concludes that Idaho Power's positions with regard to Bridger coal costs appear logical, reasonable and consistent. In addition, Bridger Coal Company profits flow to Idaho Power subsidiary IERCO and IERCO profits flow back to customers in Idaho Power Company general rate cases. Staff has not identified any justification to reject or modify the Bridger coal costs proposed by the Company and included in base power supply costs in this filing. Therefore, Staff continues to support additional normalized base power supply costs of $63.7 million.

B. Rates

The Company and Staff are both proposing a substantial decrease in PCA rates of approximately $147 million. Under the Stipulation a PCA reduction of this magnitude allows the Company to move $63.7 million (Case No. IPC-E-10-01, Order No. 31042) in increased normal power supply costs into base rates along with $25 million in other costs. The Stipulation further requires that the Base Rate increase be spread to customer classes and rate components within each customer class on an equal percentage of revenue basis, except for Residential and Small Commercial customer charges, which are to remain unchanged. Company witness Tatum provided the calculation of the new base rates in Exhibit No. 2, pages 2 through 25. Staff has reviewed these calculations and agrees that they are correct. Staff Attachment E, page 2, shows the average increase in base rates by customer class.

Combined PCA and Base Rates

Attachment E, page 3 shows the combined impact by customer class of Staff-proposed changes in PCA and base rates. The impact is measured against all billed revenue, not just base rates. Again, the percentage changes vary widely. The decrease is $58.2 million, which averages 6.49% across all customer classes. The Schedule 1 Residential class decrease is 3.24%.

Other PCA Attachments

The Staff has included three other Attachments that provide summary or historical information concerning the PCA. Staff Attachment F summarizes PCA expense amounts and rate components for this case. Page 1 shows the Company's case and page 2 shows the Staff's case. The Attachments also show 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 including the Company and Staff Proposals in this case. Attachment H graphically shows base rates and PCA rates for the Residential Customer Class from 1994 to the present time. It also shows the impact of the Company and Staff base rate and PCA rate proposals in this case.

CONSUMER ISSUES

Idaho Power's PCA Application, filed on April 15, 2010, contained both the customer notice and press release. Staff reviewed the notice and press release and determined that they complied with the requirements of Rule 125, IPUC Rules of Procedure, IDAPA 31.01.01. The customer notice was mailed with Idaho Power's cyclical billings beginning April 23, 2010 and ending May 24, 2010. Customers had until May 18, 2010 to file comments. In addition to describing the current filing, the customer notice also mentions proposed rate increases associated with the recovery of Advanced Metering Infrastructure investment (Case No. IPC-E-10-06), the annual Fixed Cost Adjustment (Case No. IPC-E-10-07), and the recovery of Defined Benefit Pension Expense (Case No. IPC-E-10-08). The customer notice recognizes that the Company proposed 6.5% overall rate decrease in this case (IPC-E-10-12) will be offset by any increase granted by the Commission in the other three cases. The notice states, "If the three proposals are approved along with the proposed PCA reduction, customers will experience a $46.6 million overall rate reduction, or an average of 5.2%."

As of May 17, 2010, two customers had submitted comments to the Commission regarding the PCA. One customer is in favor of the proposed reduction in the PCA charge, though the customer feels that the reduction should be larger. The other customer questions why the proposed PCA reduction is less for residential customers than the overall proposed decrease. The customer also feels that residential customers are subsidizing other classes of customers, all electric residential customers are being unfairly penalized, and it is wrong to use rate schedules to force energy conservation.

STAFF RECOMMENDATION

The Staff recommends that the Commission approve the base rate increases filed by the Company and reviewed by Staff. The increase has been filed in conformance with Order No. 30978 issued in Case No. IPC-E-09-30.

The Staff further recommends that the Commission approve a PCA rate of 0.3114 ¢/kWh for the June 1, 2010 through May 31, 2011 period. This PCA rate differs from the Company's proposal due to the true-up interest adjustment recommended by Staff in these comments. The Staff recommends that base rate changes and PCA rate changes be effective June 1, 2010.

Respectfully submitted this 18th day of May 2010.

Weldon B. Stutzman
Deputy Attorney General

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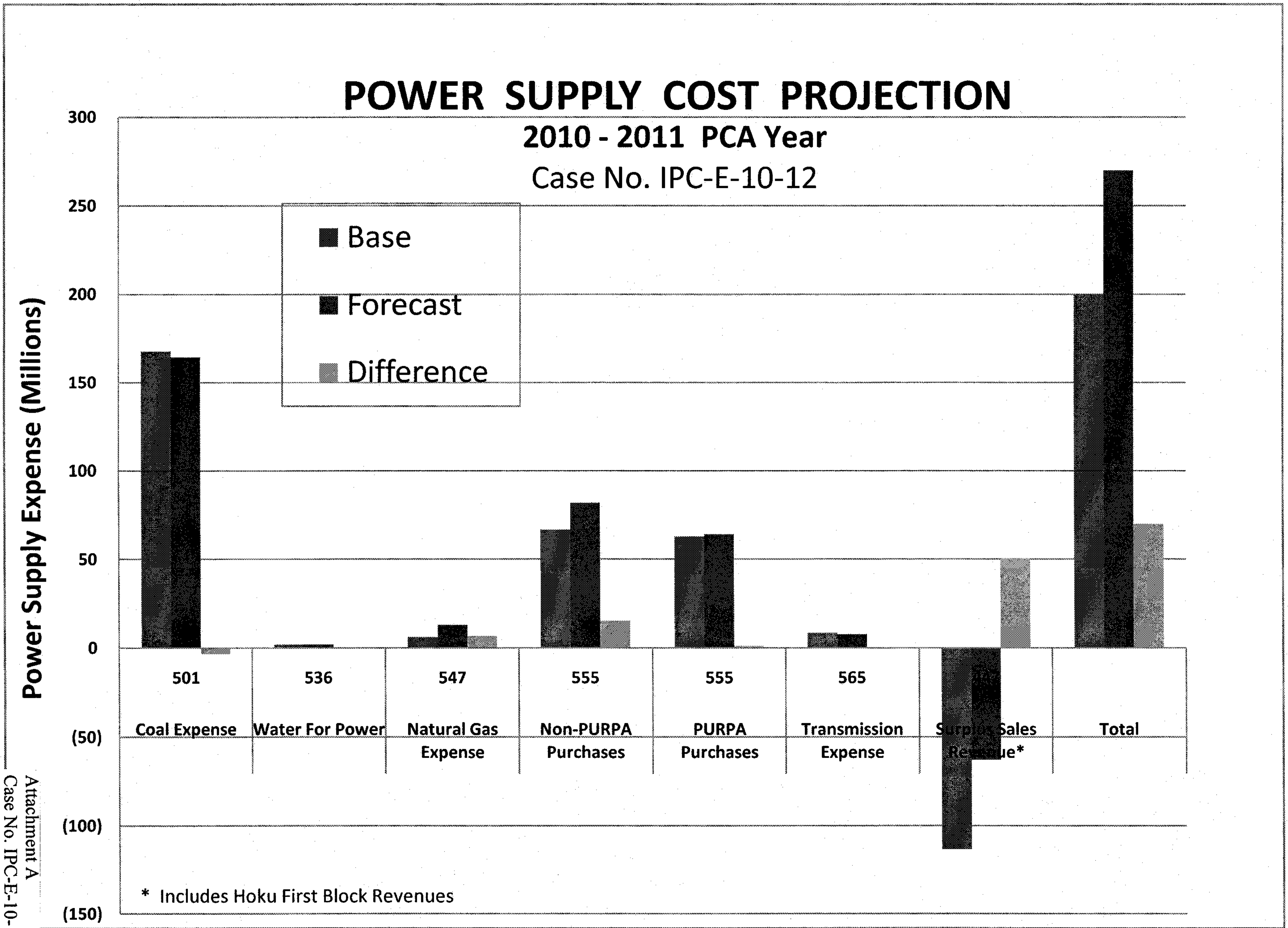

Attachment A
Case No. IPC-E-10-12
Staff Comments
5/18/10

2010-2011 PCA - Eighteenth Annual
IPC-E-10-12
Company Case

(a) Line	(b) Description	(c) Units	(d) Base	(e) Forecast	(f) Difference	(g) Rate
1	**Projection 2010-2011:**					
2	PCA Expense (95%)	($)	157,918,683	205,892,837		
3	Hoku First Block Revenue Reduction	($)		(20,670,405)		
4	Renewable Energy Credits & SO2 Benefits	($)		(7,606,860)		
5	Difference	($)		177,615,572	19,696,889	
6	Sharing Percentage	(%)			0.95	
7	Shared Difference	($)			18,712,045	
8	Normalized System Firm Sales	(MWH)			14,188,579	
9	Rate for 95 % Items	(¢/kWh)			0.1319	0.1319
10						
11	PCA Expense (100%)	($)	62,851,454	64,054,993	1,203,539	
12	Normalized System Firm Sales	(MWH)			14,188,579	
13	Rate for 100% Items	(¢/kWh)			0.0085	0.0085
14						
15	Total Forecast Rate	(¢/kWh)				**0.1404**
16						
17						
18			($)	(MWh)	($/MWh)	(¢/kWh)
19						
20	**True-Up of 2009-2010:**		11,963,777	13,467,929	0.888316014	**0.0888**
21						
22						
23						
24	**True-Up of the True-Up:**		11,284,407	13,467,929	0.837872475	**0.0838**
25						
26	**PCA Rates:**					
27	PCA Rate Adjustment From Base	(¢/kWh)				**0.3130**
28	PCA Rate Currently in Effect	(¢/kWh)				1.4022
29	Difference - Last Year to This Year	(¢/kWh)				(1.0892)
30						
31	Note: Negative rates and amounts indicate benefits to ratepayers.					

2010-2011 PCA - Eighteenth Annual
IPC-E-10-12
Staff Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Projection 2010-2011:**					
2	PCA Expense (95%)	($)	157,918,683	205,892,837		
3	Hoku First Block Revenue Reduction	($)		(20,670,405)		
4	Renewable Energy Credits & SO2 Benefits	($)		(7,606,860)		
5	Difference	($)		177,615,572	19,696,889	
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9	Rate for 95 % Items	(¢/kWh)			0.1319	0.1319
10						
11	PCA Expense (100%)	($)	62,851,454	64,054,993	1,203,539	
12	Normalized System Firm Sales	(MWH)			14,188,579	
13	Rate for 100% Items	(¢/kWh)			0.0085	0.0085
14						
15	Total Forecast Rate	(¢/kWh)				**0.1404**
16						
17						
18			($)	(MWh)	($/MWh)	(¢/kWh)
19						
20	**True-Up of 2009-2010:**		11,963,777			
21	Staff Interest Adjustment		(215,028)			
22	Total True-Up		11,748,749	13,467,929	0.872350084	**0.0872**
23						
24	**True-Up of the True-Up:**		11,284,407	13,467,929	0.837872475	**0.0838**
25						
26	**PCA Rates:**					
27	PCA Rate Adjustment From Base	(¢/kWh)				$\boxed{\textbf{0.3114}}$
28	PCA Rate Currently in Effect	(¢/kWh)				1.4022
29	Difference - Last Year to This Year	(¢/kWh)				(1.0908)
30						
31	Note: Negative rates and amounts indicate benefits to ratepayers.					

TRUE-UP CALCULATIONS FOR 2009 - 2010
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-10-12
Base Costs are Redistributed

1			2009	2009	2009	2009	2009	2009	2009
2	DESCRIPTION	Units	APR	MAY	JUN	JUL	AUG	SEPT	OCT
3	**PCA Revenue**								
4	Normalized Idaho Jurisd. Sales	MWh	968,949	998,195	1,152,831	1,361,266	1,424,275	1,310,616	1,062,389
5	Forecast Rate	m/KWh	0.000	0.000	4.967	4.967	4.967	4.967	4.967
6	Revenue	$	0	0	5,726,112	6,761,408	7,074,374	6,509,830	5,276,886
7									
8	**Load Change Adjustment**								
9	Actual System Firm Load - Adjusted	MWh	1,061,759	1,297,111	1,200,919	1,700,075	1,502,171	1,285,192	1,065,182
10	Normalized Firm Load	MWh	1,077,297	1,254,940	1,437,122	1,734,214	1,593,733	1,282,425	1,138,449
11	Load Change	MWh	(15,538)	42,171	(236,203)	(34,139)	(91,562)	2,767	(73,267)
12	Expense Adjustment	$	413,777	(1,123,014)	6,290,086	909,122	2,438,296	(73,685)	1,951,100
13									
14	**Non-QF PCA**								
15	ACTUAL:								
16	Water Lease Purchases	$	0	0	0	0	1,200,045	400,015	0
17	Fuel Expense - Coal	$	8,481,367	8,571,464	5,925,943	11,314,410	12,577,179	11,720,992	11,894,343
18	Fuel Expense - Gas	$	307,966	481,747	506,772	3,180,020	9,211,177	1,366,288	326,326
19	Non-Firm Purchases	$	2,886,846	2,623,404	3,764,629	21,356,025	14,694,297	12,543,806	3,655,533
20	Third Party Transmission	$	482,242	178,933	1,114,419	1,283,666	1,108,210	399,525	656,302
21	Surplus Sales	$	(12,227,758)	(7,805,582)	(5,537,025)	(8,962,762)	(4,675,499)	(8,657,434)	(8,671,753)
22	Hoku First Block Energy	$							
23	Expense Adjustment	$	413,777	(1,123,014)	6,290,086	909,122	2,438,296	(73,685)	1,951,100
24	Sub-Total	$	344,439	2,926,952	12,064,823	29,080,481	36,553,705	17,699,506	9,811,850
25									
26	BASE:								
27	Water for Power (Leases)	$	4,734	4,664	5,646	6,868	7,385	6,558	4,994
28	Fuel Expense - Coal	$	9,357,518	9,219,352	11,159,307	13,575,913	14,597,532	12,963,217	9,869,564
29	Fuel Expense - Gas	$	429,483	423,141	512,179	623,095	669,984	594,974	452,984
30	Non-Firm Purchases	$	4,012,962	3,953,710	4,785,657	5,822,016	6,260,137	5,559,262	4,232,552
31	Third Party Transmission	$	734,112	723,272	875,465	1,065,051	1,145,199	1,016,984	774,282
32	Surplus Sales	$	(8,173,502)	(8,052,819)	(9,747,309)	(11,858,140)	(12,750,492)	(11,322,969)	(8,620,759)
33	Sub-Total	$	6,365,307	6,271,320	7,590,945	9,234,803	9,929,745	8,818,026	6,713,617
34									
35	Change From Base	$	(6,020,868)	(3,344,368)	4,473,878	19,845,678	26,623,960	8,881,480	3,098,233
36	Emission Allowance Sales Credit	$	0	0	0	0	0	0	0
37	Green Tag Sales Credit	$	0	0	0	0	0	0	0
38	Sub-Total	$	(6,020,868)	(3,344,368)	4,473,878	19,845,678	26,623,960	8,881,480	3,098,233
39									
40	Deferral (Shared and Allocated)	$	(5,422,394)	(3,011,938)	4,029,175	17,873,017	23,977,538	7,998,661	2,790,269
41									
42	**QF Deferral**								
43	Actual (includes Net Metering)	$	3,306,868	4,930,532	7,579,069	9,186,803	8,440,558	7,261,911	5,471,254
44	Base	$	4,436,330	4,370,826	5,290,544	6,436,239	6,920,581	6,145,765	4,679,087
45									
46	Change From Base	$	(1,129,462)	559,706	2,288,525	2,750,564	1,519,977	1,116,146	792,167
47	Deferral (Allocated)	$	(1,070,730)	530,601	2,169,521	2,607,534	1,440,938	1,058,106	750,975
48									
49	**Total Deferral** (-6+40+47)	$	(6,493,124)	(2,481,336)	472,584	13,719,143	18,344,103	2,546,938	(1,735,642)
50									
51	**Principal Balances**								
52	Beginning Balance	$	0	(6,493,124)	(8,974,460)	(8,501,876)	5,217,267	23,561,370	26,108,308
53	Amount Deferred	$	(6,493,124)	(2,481,336)	472,584	13,719,143	18,344,103	2,546,938	(1,735,642)
54	Ending Balance	$	(6,493,124)	(8,974,460)	(8,501,876)	5,217,267	23,561,370	26,108,308	24,372,665
55									
56	**Interest Balances**								
57	Accrual thru Prior Month	$	0	221	(10,600)	(25,556)	(39,726)	(31,030)	12,518
58	Interest @ 2% per Year	$	0	(10,822)	(14,957)	(14,170)	8,695	39,269	43,514
59	Prior Month's Interest Adj.	$	221	0	2	0	0	4,280	0
60	Total Current Month Interest	$	221	(10,822)	(14,956)	(14,170)	8,696	43,549	43,514
61	Interest Accrued to Date	$	221	(10,600)	(25,556)	(39,726)	(31,030)	12,518	56,032
62	**Balance (True-Up & Interest)**	$	(6,492,903)	(8,985,061)	(8,527,432)	5,177,541	23,530,340	26,120,826	24,428,697
63									
64	**True-Up of the True-Up**								
65	True-Up Revenues (Collections)	$	7,549,074	7,461,834	9,159,672	11,231,894	12,693,477	11,529,057	9,507,677
66									
67	Beginning Balance	$	22,003,335	119,733,074	112,470,795	101,719,115	90,656,754	78,114,371	66,715,505
68	Adjustments:								
69	2008-09 PCA Transfer - ON 30828	$	107,891,769	0	0	0	0	0	0
70	Emission Allowance - ON 30790	$	(2,815,134)	0	(1,776,498)	0	0	0	0
71	Correction for Change in Base	$	(9,606)	0	0	0	0	0	0
72	Sub-Total	$	127,070,364	119,733,074	110,694,297	101,719,115	90,656,754	78,114,371	66,715,505
73	Interest @ 2% per Year	$	211,784	199,555	184,490	169,532	151,095	130,191	111,193
74	Revenue Applied to Interest	$	211,784	199,555	184,490	169,532	151,095	130,191	111,193
75	Revenue Applied to Balance	$	7,337,290	7,262,279	8,975,182	11,062,362	12,542,383	11,398,866	9,396,485
76	**True-Up of the True-Up Balance**	$	119,733,074	112,470,795	101,719,115	90,656,754	78,114,371	66,715,505	57,319,020
77									
78	Note: Negative amounts indicate benefit to ratepayers								

Attachment C
Case No. IPC-E-10-12
Staff Comments
5/18/10 Page 1 of 2

TRUE-UP CALCULATIONS FOR 2009 - 2010
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-10-12
Base Costs are Redistributed

1			2009	2009	2010	2010	2010	
2	DESCRIPTION	Units	NOV	DEC	JAN	FEB	MAR	TOTALS
3	**PCA Revenue**							
4	Normalized Idaho Jurisd. Sales	MWh	1,000,733	1,125,561	1,221,034	1,165,642	1,047,199	13,838,690
5	Forecast Rate	m/KWh	4.967	4.967	4.967	4.967	4.967	
6	Revenue	$	4,970,641	5,590,661	6,064,876	5,789,744	5,201,437	58,965,969
7								
8	**Load Change Adjustment**							
9	Actual System Firm Load - Adjusted	MWh	1,114,814	1,370,795	1,234,086	1,057,786	1,084,503	14,974,393
10	Normalized Firm Load	MWh	1,184,277	1,443,579	1,351,898	1,184,072	1,181,622	15,863,628
11	Load Change	MWh	(69,463)	(72,784)	(117,812)	(126,286)	(97,119)	(889,235)
12	Expense Adjustment	$	1,849,800	1,938,238	3,137,334	3,362,996	2,586,279	23,680,328
13								
14	**Non-QF PCA**							
15	ACTUAL:							
16	Water Lease Purchases	$	0	148,500	0	186	457,160	2,205,906
17	Fuel Expense - Coal	$	10,530,410	11,423,333	12,256,779	11,916,054	11,892,098	128,504,371
18	Fuel Expense - Gas	$	284,138	1,802,820	278,633	279,653	394,787	18,420,326
19	Non-Firm Purchases	$	4,362,872	7,003,524	4,149,052	3,736,883	2,855,994	83,632,863
20	Third Party Transmission	$	419,383	79,664	274,338	364,046	331,387	6,692,114
21	Surplus Sales	$	(3,465,388)	(1,466,704)	(11,007,285)	(12,553,414)	(9,326,830)	(94,357,434)
22	Hoku First Block Energy	$		(2,350)	2,350	0	(611)	(611)
23	Expense Adjustment	$	1,849,800	1,938,238	3,137,334	3,362,996	2,586,279	23,680,328
24	Sub-Total	$	13,981,213	20,927,025	9,091,200	7,106,405	9,190,265	168,777,864
25								
26	BASE:							
27	Water for Power (Leases)	$	4,774	5,406	5,846	5,522	5,122	67,519
28	Fuel Expense - Coal	$	9,433,771	10,684,589	11,554,391	10,914,656	10,124,913	133,454,723
29	Fuel Expense - Gas	$	432,982	490,391	530,313	500,951	464,703	6,125,180
30	Non-Firm Purchases	$	4,045,663	4,582,075	4,955,089	4,680,739	4,342,059	57,231,921
31	Third Party Transmission	$	740,094	838,222	906,460	856,271	794,314	10,469,726
32	Surplus Sales	$	(8,240,106)	(9,332,657)	(10,092,403)	(9,533,614)	(8,843,797)	(116,568,567)
33	Sub-Total	$	6,417,178	7,268,026	7,859,696	7,424,525	6,887,314	90,780,502
34								
35	Change From Base	$	7,564,035	13,658,999	1,231,504	(318,120)	2,302,951	77,997,362
36	Emission Allowance Sales Credit	$	0	0	0	0	0	0
37	Green Tag Sales Credit	$	0	0	0	0	(665,788)	(665,788)
38	Sub-Total		7,564,035	13,658,999	1,231,504	(318,120)	1,637,163	77,331,574
39								
40	Deferral (Shared and Allocated)	$	6,812,170	12,301,294	1,109,092	(286,499)	1,474,429	69,644,815
41								
42	**QF Deferral**							
43	Actual (includes Net Metering)	$	4,812,274	3,893,759	3,773,989	2,929,766	2,757,985	64,344,768
44	Base	$	4,472,480	5,065,484	5,477,851	5,174,557	4,800,145	63,269,889
45								
46	Change From Base	$	339,794	(1,171,725)	(1,703,862)	(2,244,791)	(2,042,160)	1,074,879
47	Deferral (Allocated)	$	322,125	(1,110,795)	(1,615,261)	(2,128,062)	(1,935,968)	1,018,985
48								
49	**Total Deferral** (-6+40+47)	$	2,163,654	5,599,838	(6,571,045)	(8,204,305)	(5,662,976)	11,697,832
50								
51	**Principal Balances**							
52	Beginning Balance	$	24,372,665	26,536,319	32,136,157	25,565,112	17,360,808	
53	Amount Deferred	$	2,163,654	5,599,838	(6,571,045)	(8,204,305)	(5,662,976)	11,697,832
54	Ending Balance	$	26,536,319	32,136,157	25,565,112	17,360,808	11,697,832	
55								
56	**Interest Balances**							
57	Accrual thru Prior Month	$	56,032	96,653	140,883	194,450	237,010	
58	Interest @ 2% per Year	$	40,621	44,227	53,560	42,609	28,935	261,481
59	Prior Month's Interest Adj.	$	0	3	6	(48)	0	4,464
60	Total Current Month Interest	$	40,621	44,230	53,567	42,561	28,935	265,945
61	Interest Accrued to Date	$	96,653	140,883	194,450	237,010	265,945	
62	**Balance (True-Up & Interest)**	$	26,632,973	32,277,040	25,759,562	17,597,818	11,963,777	**11,963,777**
63								
64	**True-Up of the True-Up**							
65	True-Up Revenues (Collections)	$	8,389,342	9,972,366	10,552,232	8,867,580	8,576,349	115,490,555
66								
67	Beginning Balance	$	57,319,020	49,025,210	39,134,552	28,647,544	19,827,710	22,003,335
68	Adjustments:							
69	2008-09 PCA Transfer - ON 30828	$	0	0	0	0	0	107,891,769
70	Emission Allowance - ON 30790	$	0	0	0	0	0	(4,591,632)
71	Correction for Change in Base	$	0	0	0	0	0	(9,606)
72	Sub-Total	$	57,319,020	49,025,210	39,134,552	28,647,544	19,827,710	125,293,866
73	Interest @ 2% per Year	$	95,532	81,709	65,224	47,746	33,046	
74	Revenue Applied to Interest	$	95,532	81,709	65,224	47,746	33,046	1,481,096
75	Revenue Applied to Balance	$	8,293,810	9,890,658	10,487,008	8,819,834	8,543,303	114,009,459
76	**True-Up of the True-Up Balance**	$	49,025,210	39,134,552	28,647,544	19,827,710	11,284,407	**11,284,407**
77								
78	Note: Negative amounts indicate benefit to ratepayers							

Attachment C
Case No. IPC-E-10-12
Staff Comments
5/18/10 Page 2 of 2

TRUE-UP CALCULATIONS FOR 2009 - 2010
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-10-12
Base Costs are AURORA Outputs (Not Redistributed)

1			2009	2009	2009	2009	2009	2009	2009
2	DESCRIPTION	Units	APR	MAY	JUN	JUL	AUG	SEPT	OCT
3	**PCA Revenue**								
4	Normalized Idaho Jurisd. Sales	MWh	968,949	998,195	1,152,831	1,361,266	1,424,275	1,310,616	1,062,389
5	Forecast Rate	m/KWh	0.000	0.000	4.967	4.967	4.967	4.967	4.967
6	Revenue	$	0	0	5,726,112	6,761,408	7,074,374	6,509,830	5,276,886
7									
8	**Load Change Adjustment**								
9	Actual System Firm Load - Adjusted	MWh	1,061,759	1,297,111	1,200,919	1,700,075	1,502,171	1,285,192	1,065,182
10	Normalized Firm Load	MWh	1,077,297	1,254,940	1,437,122	1,734,214	1,593,733	1,282,425	1,138,449
11	Load Change	MWh	(15,538)	42,171	(236,203)	(34,139)	(91,562)	2,767	(73,267)
12	Expense Adjustment	$	413,777	(1,123,014)	6,290,086	909,122	2,438,296	(73,685)	1,951,100
13									
14	**Non-QF PCA**								
15	ACTUAL:								
16	Water Lease Purchases	$	0	0	0	0	1,200,045	400,015	0
17	Fuel Expense - Coal	$	8,481,367	8,571,464	5,925,943	11,314,410	12,577,179	11,720,992	11,894,343
18	Fuel Expense - Gas	$	307,966	481,747	506,772	3,180,020	9,211,177	1,366,288	326,326
19	Non-Firm Purchases	$	2,886,846	2,623,404	3,764,629	21,356,025	14,694,297	12,543,806	3,655,533
20	Third Party Transmission	$	482,242	178,933	1,114,419	1,283,666	1,108,210	399,525	656,302
21	Surplus Sales	$	(12,227,758)	(7,805,582)	(5,537,025)	(8,962,762)	(4,675,499)	(8,657,434)	(8,671,753)
22	Hoku First Block Energy	$							
23	Expense Adjustment	$	413,777	(1,123,014)	6,290,086	909,122	2,438,296	(73,685)	1,951,100
24	Sub-Total	$	344,439	2,926,952	12,064,823	29,080,481	36,553,705	17,699,506	9,811,850
25									
26	BASE:								
27	Water for Power (Leases)	$	4,734	4,664	5,646	6,868	7,385	6,558	4,994
28	Fuel Expense - Coal	$	7,770,564	9,055,548	10,823,695	12,052,676	12,079,460	11,659,568	12,068,932
29	Fuel Expense - Gas	$	412,108	316,922	316,969	1,634,262	897,427	374,698	364,846
30	Non-Firm Purchases	$	1,622,208	2,041,687	5,556,509	13,343,476	7,771,064	4,853,324	2,253,223
31	Third Party Transmission	$	734,112	723,272	875,465	1,065,051	1,145,199	1,016,984	774,282
32	Surplus Sales	$	(16,822,354)	(10,712,129)	(7,561,791)	(1,499,742)	(1,507,699)	(5,290,199)	(9,136,293)
33	Sub-Total	$	(6,278,628)	1,429,964	10,016,493	26,602,591	20,392,836	12,620,933	6,329,984
34									
35	Change From Base	$	6,623,067	1,496,988	2,048,330	2,477,890	16,160,869	5,078,573	3,481,866
36	Emission Allowance Sales Credit	$	0	0	0	0	0	0	0
37	Green Tag Sales Credit	$	0	0	0	0	0	0	0
38	Sub-Total	$	6,623,067	1,496,988	2,048,330	2,477,890	16,160,869	5,078,573	3,481,866
39									
40	Deferral (Shared and Allocated)	$	5,964,734	1,348,187	1,844,726	2,231,587	14,554,478	4,573,763	3,135,769
41									
42	**QF Deferral**								
43	Actual (includes Net Metering)	$	3,306,868	4,930,532	7,579,069	9,186,803	8,440,558	7,261,911	5,471,254
44	Base	$	4,113,148	5,203,607	7,860,134	8,118,697	7,871,301	6,284,831	4,566,064
45									
46	Change From Base	$	(806,280)	(273,075)	(281,065)	1,068,106	569,257	977,080	905,190
47	Deferral (Allocated)	$	(764,354)	(258,875)	(266,450)	1,012,564	539,656	926,272	858,120
48									
49	**Total Deferral** (-6+40+47)	$	5,200,380	1,089,312	(4,147,835)	(3,517,257)	8,019,760	(1,009,795)	(1,282,997)
50									
51	**Principal Balances**								
52	Beginning Balance	$	0	5,200,380	6,289,693	2,141,857	(1,375,399)	6,644,361	5,634,566
53	Amount Deferred	$	5,200,380	1,089,312	(4,147,835)	(3,517,257)	8,019,760	(1,009,795)	(1,282,997)
54	Ending Balance	$	5,200,380	6,289,693	2,141,857	(1,375,399)	6,644,361	5,634,566	4,351,569
55									
56	**Interest Balances**								
57	Accrual thru Prior Month	$	0	221	8,889	19,373	22,943	20,651	36,005
58	Interest @ 2% per Year	$	0	8,667	10,483	3,570	(2,292)	11,074	9,391
59	Prior Month's Interest Adj.	$	221	0	2	0	0	4,280	0
60	Total Current Month Interest	$	221	8,667	10,484	3,570	(2,292)	15,354	9,391
61	Interest Accrued to Date	$	221	8,889	19,373	22,943	20,651	36,005	45,396
62	**Balance (True-Up & Interest)**	$	5,200,602	6,298,582	2,161,230	(1,352,456)	6,665,012	5,670,571	4,396,965
63									
64	**True-Up of the True-Up**								
65	True-Up Revenues (Collections)	$	7,549,074	7,461,834	9,159,672	11,231,894	12,693,477	11,529,057	9,507,677
66									
67	Beginning Balance	$	22,003,335	119,733,074	112,470,795	101,719,115	90,656,754	78,114,371	66,715,505
68	Adjustments:								
69	2008-09 PCA Transfer - ON 30828 (	$	107,891,769	0	0	0	0	0	0
70	Emission Allowance - ON 30790	$	(2,815,134)	0	(1,776,498)	0	0	0	0
71	Correction for Change in Base	$	(9,606)	0	0	0	0	0	0
72	Sub-Total	$	127,070,364	119,733,074	110,694,297	101,719,115	90,656,754	78,114,371	66,715,505
73	Interest @ 2% per Year	$	211,784	199,555	184,490	169,532	151,095	130,191	111,193
74	Revenue Applied to Interest	$	211,784	199,555	184,490	169,532	151,095	130,191	111,193
75	Revenue Applied to Balance	$	7,337,290	7,262,279	8,975,182	11,062,362	12,542,383	11,398,866	9,396,485
76	**True-Up of the True-Up Balance**	$	119,733,074	112,470,795	101,719,115	90,656,754	78,114,371	66,715,505	57,319,020
77									
78	Note: Negative amounts indicate benefit to ratepayers								

Attachment D
Case No. IPC-E-10-12
Staff Comments

TRUE-UP CALCULATIONS FOR 2009 - 2010
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-10-12
Base Costs are AURORA Outputs (Not Redistributed)

1			2009	2009	2010	2010	2010	
2	DESCRIPTION	Units	NOV	DEC	JAN	FEB	MAR	TOTALS
3	**PCA Revenue**							
4	Normalized Idaho Jurisd. Sales	MWh	1,000,733	1,125,561	1,221,034	1,165,642	1,047,199	13,838,690
5	Forecast Rate	m/KWh	4.967	4.967	4.967	4.967	4.967	
6	Revenue	$	4,970,641	5,590,661	6,064,876	5,789,744	5,201,437	58,965,969
7								
8	**Load Change Adjustment**							
9	Actual System Firm Load - Adjusted	MWh	1,114,814	1,370,795	1,234,086	1,057,786	1,084,503	14,974,393
10	Normalized Firm Load	MWh	1,184,277	1,443,579	1,351,898	1,184,072	1,181,622	15,863,628
11	Load Change	MWh	(69,463)	(72,784)	(117,812)	(126,286)	(97,119)	(889,235)
12	Expense Adjustment	$	1,849,800	1,938,238	3,137,334	3,362,996	2,586,279	23,680,328
13								
14	**Non-QF PCA**							
15	ACTUAL:							
16	Water Lease Purchases	$	0	148,500	0	186	457,160	2,205,906
17	Fuel Expense - Coal	$	10,530,410	11,423,333	12,256,779	11,916,054	11,892,098	128,504,371
18	Fuel Expense - Gas	$	284,138	1,802,820	278,633	279,653	394,787	18,420,326
19	Non-Firm Purchases	$	4,362,872	7,003,524	4,149,052	3,736,883	2,855,994	83,632,863
20	Third Party Transmission	$	419,383	79,664	274,338	364,046	331,387	6,692,114
21	Surplus Sales	$	(3,465,388)	(1,466,704)	(11,007,285)	(12,553,414)	(9,326,830)	(94,357,434)
22	Hoku First Block Energy	$		(2,350)	2,350	0	(611)	(611)
23	Expense Adjustment	$	1,849,800	1,938,238	3,137,334	3,362,996	2,586,279	23,680,328
24	Sub-Total	$	13,981,213	20,927,025	9,091,200	7,106,405	9,190,265	168,777,864
25								
26	BASE:							
27	Water for Power (Leases)	$	4,774	5,406	5,846	5,522	5,122	67,519
28	Fuel Expense - Coal	$	11,704,004	12,108,968	11,834,031	11,045,620	11,251,657	133,454,723
29	Fuel Expense - Gas	$	467,067	370,512	348,031	306,063	316,275	6,125,180
30	Non-Firm Purchases	$	4,933,733	7,084,747	4,332,527	1,895,241	1,544,182	57,231,921
31	Third Party Transmission	$	740,094	838,222	906,460	856,271	794,314	10,469,726
32	Surplus Sales	$	(4,058,642)	(6,138,836)	(9,823,963)	(22,608,930)	(21,407,989)	(116,568,567)
33	Sub-Total	$	13,791,030	14,269,019	7,602,932	(8,500,213)	(7,496,439)	90,780,502
34								
35	Change From Base	$	190,183	6,658,006	1,488,268	15,606,618	16,686,704	77,997,362
36	Emission Allowance Sales Credit	$	0	0	0	0	0	0
37	Green Tag Sales Credit	$	0	0	0	0	(665,788)	(665,788)
38	Sub-Total		190,183	6,658,006	1,488,268	15,606,618	16,020,916	77,331,574
39								
40	Deferral (Shared and Allocated)	$	171,279	5,996,200	1,340,334	14,055,320	14,428,437	69,644,815
41								
42	**QF Deferral**							
43	Actual (includes Net Metering)	$	4,812,274	3,893,759	3,773,989	2,929,766	2,757,985	64,344,768
44	Base	$	3,994,318	4,427,260	3,784,877	3,795,312	3,250,340	63,269,889
45								
46	Change From Base	$	817,956	(533,501)	(10,888)	(865,546)	(492,355)	1,074,879
47	Deferral (Allocated)	$	775,422	(505,759)	(10,322)	(820,537)	(466,752)	1,018,985
48								
49	**Total Deferral** (-6+40+47)	$	(4,023,939)	(100,220)	(4,734,864)	7,445,039	8,760,247	11,697,832
50								
51	**Principal Balances**							
52	Beginning Balance	$	4,351,569	327,630	227,410	(4,507,454)	2,937,585	
53	Amount Deferred	$	(4,023,939)	(100,220)	(4,734,864)	7,445,039	8,760,247	11,697,832
54	Ending Balance	$	327,630	227,410	(4,507,454)	2,937,585	11,697,832	
55								
56	**Interest Balances**							
57	Accrual thru Prior Month	$	45,396	52,648	53,197	53,582	46,022	
58	Interest @ 2% per Year	$	7,253	546	379	(7,512)	4,896	46,454
59	Prior Month's Interest Adj.	$	0	3	6	(48)	0	4,464
60	Total Current Month Interest	$	7,253	549	385	(7,560)	4,896	50,918
61	Interest Accrued to Date	$	52,648	53,197	53,582	46,022	50,918	
62	**Balance (True-Up & Interest)**	$	380,278	280,607	(4,453,872)	2,983,606	11,748,749	**11,748,749**
63								
64	**True-Up of the True-Up**							
65	True-Up Revenues (Collections)	$	8,389,342	9,972,366	10,552,232	8,867,580	8,576,349	115,490,555
66								
67	Beginning Balance	$	57,319,020	49,025,210	39,134,552	28,647,544	19,827,710	22,003,335
68	Adjustments:							
69	2008-09 PCA Transfer - ON 30828 (I	$	0	0	0	0	0	107,891,769
70	Emission Allowance - ON 30790	$	0	0	0	0	0	(4,591,632)
71	Correction for Change in Base	$	0	0	0	0	0	(9,606)
72	Sub-Total	$	57,319,020	49,025,210	39,134,552	28,647,544	19,827,710	125,293,866
73	Interest @ 2% per Year	$	95,532	81,709	65,224	47,746	33,046	
74	Revenue Applied to Interest	$	95,532	81,709	65,224	47,746	33,046	1,481,096
75	Revenue Applied to Balance	$	8,293,810	9,890,658	10,487,008	8,819,834	8,543,303	114,009,459
76	**True-Up of the True-Up Balance**	$	49,025,210	39,134,552	28,647,544	19,827,710	11,284,407	**11,284,407**
77								
78	Note: Negative amounts indicate benefit to ratepayers							

Idaho Power Company
Summary of Revenue Impact
State of Idaho
Forecasted 12-Months Ending May 31, 2011
Staff Proposal

6/1/2009 PCA Rates to 6/1/2010 PCA Rates

Line No	Tariff Description	(1) Rate Sch. No.	(2) Average Number of Customers	(3) Normalized Energy (kWh)	(4) Current Base & Current PCA Revenue	(5) PCA Revenue Adjustments	(6) Current Base & Proposed PCA Revenue	(7) Average ¢/kWh	(8) Percent Change
1	Uniform Tariff Rates:								
2	Residential Service	1	393,881	4,987,386,990	$399,143,062	($54,402,417)	$344,740,645	6.9122	-13.63%
3	Master Metered Mobile Home Park	3	22	4,910,077	$375,184	($53,559)	$321,625	6.5503	-14.28%
4	Residential Service Energy Watch	4	51	815,635	$64,413	($8,897)	$55,516	6.8065	-13.81%
5	Residential Service Time-of-Day	5	78	1,198,564	$94,533	($13,074)	$81,459	6.7964	-13.83%
6	Small General Service	7	28,214	165,753,187	16,048,391	($1,808,036)	$14,240,355	8.5913	-11.27%
7	Large General Service	9	30,996	3,489,823,046	213,702,537	($38,066,989)	$175,635,548	5.0328	-17.81%
8	Dusk to Dawn Lighting	15	-	6,605,770	1,080,560	($72,056)	$1,008,504	15.2670	-6.67%
9	Large Power Service	19	116	2,024,650,409	100,153,444	($22,084,885)	$78,068,559	3.8559	-22.05%
10	Agricultural Irrigation Service	24	16,379	1,637,091,719	110,514,365	($17,857,396)	$92,656,969	5.6599	-16.16%
11	Unmetered General Service	40	1,911	16,518,862	1,185,082	($180,187)	$1,004,895	6.0833	-15.20%
12	Street Lighting	41	262	22,975,581	2,727,147	($250,618)	$2,476,529	10.7790	-9.19%
13	Traffic Control Lighting	42	307	4,012,613	216,432	($43,770)	$172,662	4.3030	-20.22%
14	*Total Uniform Tariffs*		472,217	12,361,742,453	$845,305,150	($134,841,884)	$710,463,266	5.7473	-15.95%
15									
16	Special Contracts:								
17	Micron	26	1	511,916,530	$22,681,345	($5,583,986)	$17,097,359	3.3399	-24.62%
18	J R Simplot	29	1	186,892,532	8,203,129	($2,038,624)	$6,164,505	3.2984	-24.85%
19	DOE	30	1	248,832,751	10,636,105	($2,714,268)	$7,921,837	3.1836	-25.52%
20	Hoku	32	1	158,545,000	7,414,305	($1,729,409)	$5,684,896	3.5857	-23.33%
21	*Total Special Contracts*		4	1,106,186,813	48,934,884	(12,066,287)	36,868,597	3.3329	-24.66%
22									
23									
24	***Total Idaho Retail Sales***		472,221	13,467,929,266	$894,240,034	($146,908,171)	$747,331,863	5.5490	-16.43%

Idaho Power Company
Summary of Revenue Impact
State of Idaho
Forecasted 12-Months Ending May 31, 2011
Staff Proposal

Present Base Rates to 6/1/2010 Base Rates

Line No	Tariff Description	(1) Rate Sch. No.	(2) Average Number of Customers	(3) Normalized Energy (kWh)	(4) Current Base Revenue	(5) Base Revenue Adjustments	(6) Proposed Base Revenue	(7) Average ¢/kWh	(8) Percent Change
1	Uniform Tariff Rates:								
2	Residential Service	1	393,881	4,987,386,990	$329,209,922	$41,397,463	$370,607,385	7.431	12.57%
3	Master Metered Mobile Home Park	3	22	4,910,077	$306,335	$38,515	$344,850	7.023	12.57%
4	Residential Service Energy Watch	4	51	815,635	$52,976	$6,660	$59,636	7.312	12.57%
5	Residential Service Time-of-Day	5	78	1,198,564	$77,727	$9,768	$87,495	7.300	12.57%
6	Small General Service	7	28,214	165,753,187	13,724,200	1,725,775	15,449,975	9.321	12.57%
7	Large General Service	9	30,996	3,489,823,046	164,768,239	20,719,214	185,487,453	5.315	12.57%
8	Dusk to Dawn Lighting	15	-	6,605,770	987,934	124,231	1,112,165	16.836	12.57%
9	Large Power Service	19	116	2,024,650,409	71,763,797	9,024,104	80,787,901	3.990	12.57%
10	Agricultural Irrigation Service	24	16,379	1,637,091,719	87,559,065	11,010,221	98,569,286	6.021	12.57%
11	Unmetered General Service	40	1,911	16,518,862	953,455	119,894	1,073,349	6.498	12.57%
12	Street Lighting	41	262	22,975,581	2,404,983	302,407	2,707,390	11.784	12.57%
13	Traffic Control Lighting	42	307	4,012,613	160,167	20,140	180,307	4.494	12.57%
14	*Total Uniform Tariffs*		472,217	12,361,742,453	$671,968,800	$84,498,392	$756,467,192	6.119	12.57%
15									
16	Special Contracts:								
17	Micron	26	1	511,916,530	$15,503,251	$1,949,266	$17,452,517	3.409	12.57%
18	J R Simplot	29	1	186,892,532	5,582,522	701,929	6,284,451	3.363	12.57%
19	DOE	30	1	248,832,751	7,146,972	898,659	8,045,631	3.233	12.57%
20	Hoku	32	1	158,545,000	5,191,187	652,734	5,843,921	3.686	12.57%
21	*Total Special Contracts*		4	1,106,186,813	33,423,932	4,202,588	37,626,520	3.401	12.57%
22									
23									
24	***Total Idaho Retail Sales***		472,221	13,467,929,266	$705,392,732	$88,700,980	$794,093,712	5.896	12.57%

Idaho Power Company
Summary of Revenue Impact
State of Idaho
Forecasted 12-Months Ending May 31, 2011
Staff Proposal

Present Billed Rates to 6/1/2010 Billed Rates

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	393,881	4,987,386,990	$401,781,390	($13,004,954)	$388,776,436	7.795	-3.24%
3	Master Metered Mobile Home Park	3	22	4,910,077	$377,781	($15,044)	$362,737	7.388	-3.98%
4	Residential Service Energy Watch	4	51	815,635	$64,844	($2,237)	$62,607	7.676	-3.45%
5	Residential Service Time-of-Day	5	78	1,198,564	$95,167	($3,306)	$91,861	7.664	-3.47%
6	Small General Service	7	28,214	165,753,187	16,136,074	(82,261)	16,053,813	9.685	-0.51%
7	Large General Service	9	30,996	3,489,823,046	213,702,537	(17,347,775)	196,354,762	5.626	-8.12%
8	Dusk to Dawn Lighting	15	-	6,605,770	1,080,560	52,175	1,132,735	17.148	4.83%
9	Large Power Service	19	116	2,024,650,409	100,153,444	(13,060,781)	87,092,663	4.302	-13.04%
10	Agricultural Irrigation Service	24	16,379	1,637,091,719	110,514,365	(6,847,175)	103,667,190	6.332	-6.20%
11	Unmetered General Service	40	1,911	16,518,862	1,185,082	(60,293)	1,124,789	6.809	-5.09%
12	Street Lighting	41	262	22,975,581	2,727,147	51,789	2,778,936	12.095	1.90%
13	Traffic Control Lighting	42	307	4,012,613	216,432	(23,630)	192,802	4.805	-10.92%
14	*Total Uniform Tariffs*		472,217	12,361,742,453	$848,034,823	($50,343,492)	$797,691,331	6.453	-5.94%
15									
16	Special Contracts:								
17	Micron	26	1	511,916,530	$22,681,345	($3,634,720)	$19,046,625	3.721	-16.03%
18	J R Simplot	29	1	186,892,532	8,203,129	(1,336,695)	6,866,434	3.674	-16.29%
19	DOE	30	1	248,832,751	10,636,105	(1,815,609)	8,820,496	3.545	-17.07%
20	Hoku	32	1	158,545,000	7,414,305	(1,076,675)	6,337,630	3.997	-14.52%
21	*Total Special Contracts*		4	1,106,186,813	48,934,884	(7,863,699)	41,071,185	3.713	-16.07%
22									
23									
24	***Total Idaho Retail Sales***		472,221	13,467,929,266	$896,969,707	($58,207,191)	$838,762,516	6.228	-6.49%

Division of Power Costs
IPC-E-10-12
Company Case

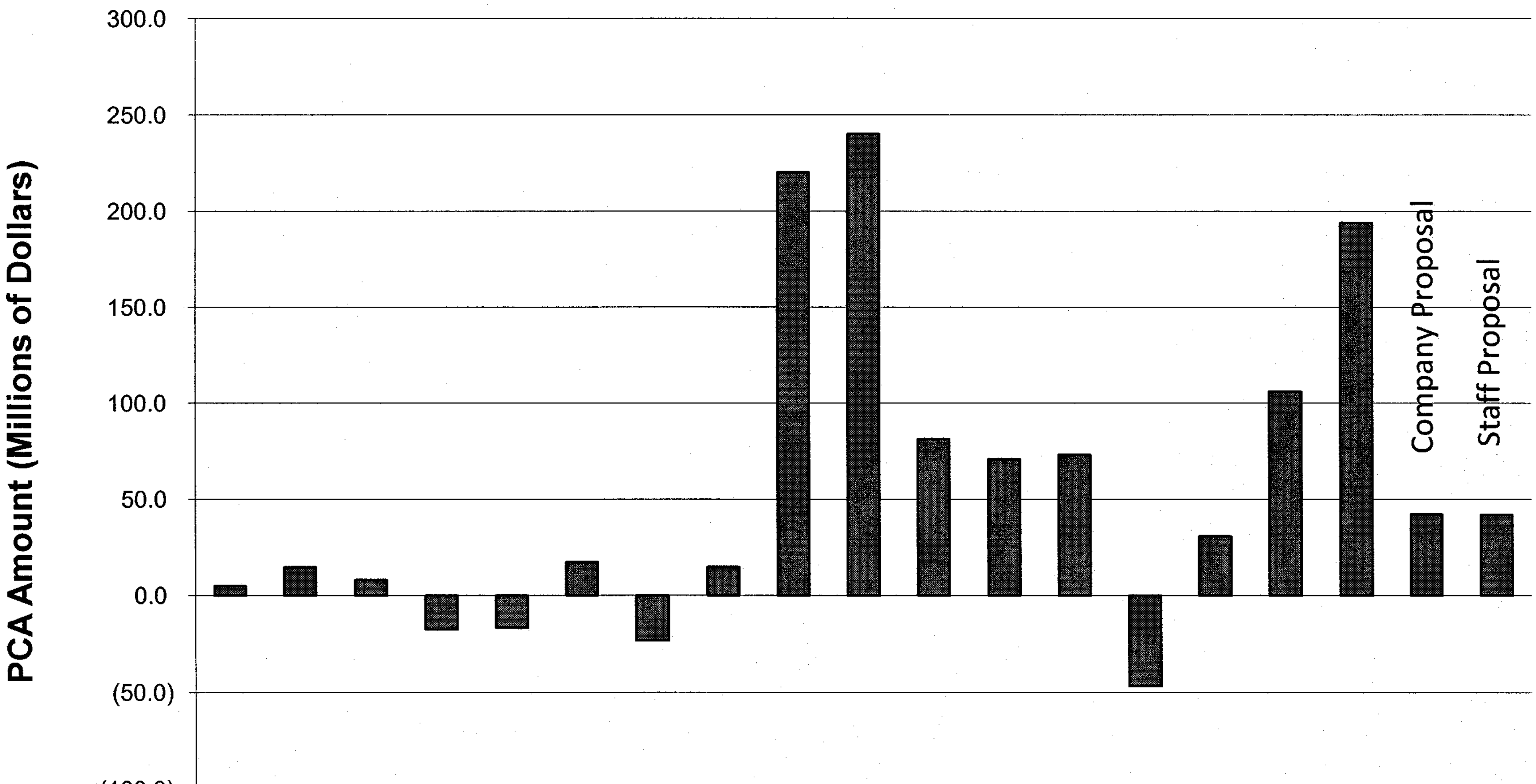
Description	Initial Amount ($)	Allocated to Other Jurisdictions ($)	Shared with Shareholders ($)	Idaho Customer Revenue Requirement ($)	**Idaho PCA Rates (¢/kWh)**
Forecast (2010-2011)					
Non-QF Power Supply Cost Difference	19,696,889	1,024,238	933,633	17,739,018	
QF Power Supply Cost Difference	1,203,539	62,584		1,140,955	
Sub-Total	20,900,428	1,086,822	933,633	18,879,973	**0.1404**
True Up (2009-2010)					
Revenue from Forecast Rate	(58,965,969)			(58,965,969)	
Non-QF Power Supply Cost Difference	54,317,034	2,824,486	2,574,627	48,917,921	
Load Growth Adjustment	23,680,328	1,231,377	1,122,448	21,326,503	
Green Tag Sales Credit	(665,788)	(34,621)	(31,558)	(599,609)	
QF Power Supply Cost Difference	1,074,879	55,894	0	1,018,985	
Interest During Deferral Period	265,945			265,945	
Sub-Total	19,706,429	4,077,136	3,665,517	11,963,777	**0.0888**
True Up of the True Up					
Amount Carried Forward	22,003,335			22,003,335	
Other Limited Term Adjustments:					
2008-2009 PCA Transfer	107,891,769			107,891,769	
Emission Allowance - ON 30790	(4,591,632)			(4,591,632)	
Correction for Change in Base	(9,606)			(9,606)	
Interest During Amortization	1,481,096			1,481,096	
Collections from True Up Rate	(115,490,555)			(115,490,555)	
Sub-Total	11,284,407	0	0	11,284,407	**0.0838**
Total Power Cost Adjustment (PCA)	51,891,264	5,163,958	4,599,149	42,128,157	**0.3130**

Division of Power Costs
IPC-E-10-12
Staff Case

Description	Initial Amount ($)	Allocated to Other Jurisdictions ($)	Shared with Shareholders ($)	Idaho Customer Revenue Requirement ($)	**Idaho PCA Rates (¢/kWh)**
Forecast (2010-2011)					
Non-QF Power Supply Cost Difference	19,696,889	1,024,238	933,633	17,739,018	
QF Power Supply Cost Difference	1,203,539	62,584		1,140,955	
Sub-Total	20,900,428	1,086,822	933,633	18,879,973	**0.1404**
True Up (2009-2010)					
Revenue from Forecast Rate	(58,965,969)			(58,965,969)	
Non-QF Power Supply Cost Difference	54,317,034	2,824,486	2,574,627	48,917,921	
Load Growth Adjustment	23,680,328	1,231,377	1,122,448	21,326,503	
Green Tag Sales Credit	(665,788)	(34,621)	(31,558)	(599,609)	
QF Power Supply Cost Difference	1,074,879	55,894	0	1,018,985	
Interest During Deferral Period	50,917			50,917	
Sub-Total	19,491,401	4,077,136	3,665,517	11,748,749	**0.0872**
True Up of the True Up					
Amount Carried Forward	22,003,335			22,003,335	
Other Limited Term Adjustments:					
2008-2009 PCA Transfer	107,891,769			107,891,769	
Emission Allowance - ON 30790	(4,591,632)			(4,591,632)	
Correction for Change in Base	(9,606)			(9,606)	
Interest During Amortization	1,481,096			1,481,096	
Collections from True Up Rate	(115,490,555)			(115,490,555)	
Sub-Total	11,284,407	0	0	11,284,407	**0.0838**
Total Power Cost Adjustment (PCA)	51,676,236	5,163,958	4,599,149	41,913,129	**0.3114**

Attachment F
Case No. IPC-E-10-12
Staff Comments
5/18/10 Page 2 of 2

HISTORY OF PCA AMOUNTS



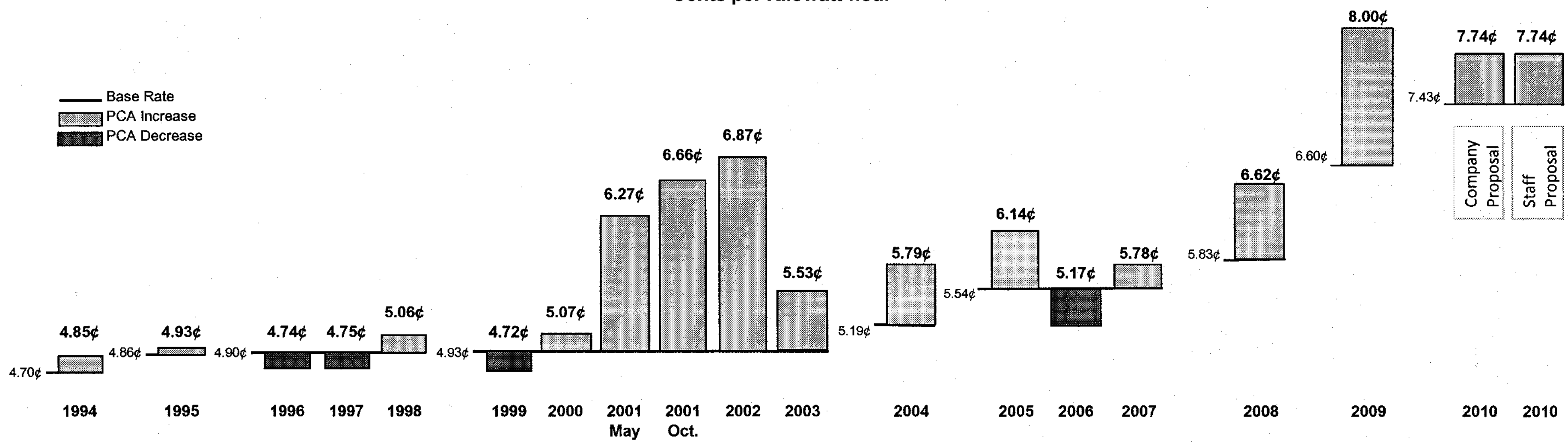
	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2010
■PCA Amounts	4.9	14.7	8.1	(17.6)	(16.7)	17.3	(23.2)	14.8	220.2	240.2	81.3	70.8	73.1	(46.8)	30.7	106.0	194.0	42.2	41.9

PCA Year

Attachment G
Case No. IPC-E-10-12
Staff Comments
5/18/10

AVERAGE RESIDENTIAL ENERGY RATES FOR IDAHO POWER COMPANY

Cents per Kilowatt-hour



These rates do not include the monthly Service Charge, BPA Credit, Energy Efficiency Rider, Fixed Cost Adjustment or any Local Franchise Fees that may apply.

Attachment H
Case No. IPC-E-10-12
Staff Comments
5/18/10

PCA History Chart 4/29/2010 KDH

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 18TH DAY OF MAY 2010, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-10-12, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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SECRETARY