WELDON B. STUTZMAN
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0318
IDAHO BAR NO. 3283

Street Address for Express Mail:
472 W. WASHINGTON
BOISE, IDAHO 83702-5983

Attorney for the Commission Staff

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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, 2009 THROUGH MAY 31, 2010.	**CASE NO. IPC-E-09-11** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, by and through its Attorney of Record, Weldon B. Stutzman, Deputy Attorney General, submits the following comments in response to Order No. 30786 issued on April 23, 2009.

BACKGROUND

Since 1993, the PCA mechanism has permitted Idaho Power to establish PCA rates to recover allowed variations from normal power supply costs. Base rates, established in a general rate case, recover normal power supply costs. The main components of variable power supply cost are fuel costs (coal and natural gas) and purchased power costs. These costs are offset with off-system sales revenues. Idaho Power Company's power supply costs vary annually based on streamflow at hydro power generating facilities, the market price of power, and other factors.

The annual PCA surcharge or credit is combined with the Company's "base rates," and other non-base rates, to produce a customer's overall energy rate.

On April 15, 2009, Idaho Power Company filed its annual power cost adjustment (PCA) Application. In this PCA Application, Idaho Power calculates that its annual power costs have increased above normal amounts. To recover the increased power costs, the Company estimates that existing PCA rates must increase to recover an additional $93.8 million. The proposed increase averages 11.4% but impacts different customer classes differently. The lowest proposed class increase is 3.8% and the largest proposed increase is 18.7% for a special contracts customer.

THE PCA MECHANISM

The annual PCA mechanism is comprised of three major components. The first component, projected or forecasted power cost, is computed using the results of the Company's most recent Operating Plan (OP Plan). This method replaces the previous method that was based on a forecast of Brownlee Reservoir inflow and a regression formula derived from rate case power supply cost data. The Commission directed use of the new method for projecting power costs in an effort to improve forecast accuracy. The old method resulted in forecasts that differed substantially from actual results. Order No. 30715. In the new method, streamflow remains a major factor used to project power costs. In addition to streamflow, the new method includes updated projections for load, market price, resource availability and many other variables. It also includes the costs of power supply transactions already made for the PCA year. The new method of projecting power supply costs is expected to be significantly more accurate.

In general, in years of abundant snowpack and streamflow, the Company's power supply costs are lower. Hydropower is the Company's lowest cost major resource. Conversely, when snowpack and resulting streamflows are low, Idaho Power must rely increasingly upon its thermal generating resources and purchased power from the regional market. The Company's thermal generating resources (coal and gas plants) and purchased power are typically much more costly than the Company's hydro-generation. Under the PCA mechanism, beginning February 1, 2009, the Company may recover 95% of the difference between projected power costs and normal power costs included in base rates. Order No. 30715.

Because the PCA includes forecasted costs, the second PCA component consists of a true up from the preceding year's forecasted costs to the actual costs incurred in the prior year. In recent years, the true-up balance has been reduced using revenue from the sale of sulfur dioxide (SO_2) allowances.

The third component is the "true-up of the true-up," or reconciliation of the previous year's true-up. This component is designed to ensure the Company recovers the actual approved costs. Idaho Power uses "normalized" power sales (measured in kilowatt-hours (kWh)) from the ensuing PCA year as the denominator to compute the adjusted true-up rate. Over- or under-recovery is balanced with the following year's true-up.

In a poor water, high cost year, Idaho ratepayers pay a large portion of Idaho Power Company's abnormal power supply costs. In a good water, low cost year, Idaho ratepayers are credited with a large portion of the below normal cost savings.

IDAHO POWER'S PCA APPLICATION

A. The PCA Components

This year's PCA Application includes the 2009-2010 forecast of power supply costs; a true-up of last year's forecasted costs to reflect actual costs and revenues; and reconciliation of the 2008-2009 PCA year true-up (the true-up of the true-up). The Company calculates that the net forecasted power supply cost is $260.1 million for the 2009-2010 PCA year. This is $106.0 million more than the $154.1 million included in Base Rates. After adjustments and PCA sharing, this results in a forecast rate of 0.5662 ¢/kWh.

Idaho Power reports that the difference between last year's normal and actual power supply costs adjusted by revenue generated from the forecast rate, the true-up component, is $107.9 million. The true-up amount becomes $103.3 million after it is reduced by approximately $4.6 million to reflect S02 sales revenues. Application, p. 4. The Company calculates the true-up portion of the PCA rate to be 0.7465 ¢/kWh.

The third PCA rate element is the "true-up of the true-up" or reconciliation of the previous year's true-up. Last year the Company under-collected the PCA deferral balance by $22.0 million. Application, p. 4. Dividing this amount by the projected 2009 Idaho jurisdictional sales of 13,838,689 MWh results in a PCA surcharge rate of 0.1590 ¢/kWh. *Id.*

Combining the three components – the projected power costs rate of 0.5662 ¢/kWh, the true-up rate of 0.7465 ¢/kWh and the true-up of the true-up rate of 0.1590 ¢/kWh – results in a proposed PCA surcharge rate for the 2009-2010 PCA year of 1.4717 ¢/kWh. This represents an increase of 0.6853 ¢/kWh above the existing PCA rate of 0.7864 ¢/kWh.

B. Impact of the Company's Rate Proposal

Idaho Power has proposed to implement the PCA rate on June 1, 2009. The proposed PCA rate represents an overall average percentage increase of 11.4% in Company revenue. Although the PCA rate is an equal cents per kWh adjustment for all customers, each customer class will receive a different percentage increase due to the different energy rates in effect for the different customer classes. The table below shows the proposed increases in the PCA rates for the major customer classes:

Customer Group (Schedule)	Percentage Increase
Residential (1)	9.30%
Small Commercial (7)	7.56%
Large Commercial (9)	12.58%
Industrial (19)	15.64%
Irrigation (24)	11.08%

The PCA rates for Idaho Power's three special-contract customers (Micron, Simplot, and the Department of Energy (INL)) would also increase. Under the Company's proposal the PCA rate increase for the three special-contract customers would be 17.68% for Micron, 18.71% for Simplot, and 18.36% for the Idaho National Laboratory.

Attachment A to these comments is a chart that shows the magnitude of the PCA for each year since its inception in 1993. For 2009, both the Company and Staff proposals are shown. Attachment B shows a history of Idaho Power's residential energy rates and identifies the PCA components. The chart also shows the Company and Staff proposals for 2009.

STAFF AUDIT AND ANALYSIS

The PCA has three components: 1) a forecast component; 2) a true-up component that corrects for the previous years forecast error; and 3) a true-up of the previous year's true-up that is a final correction. Set out below are the Staff's comments on the three PCA components.

A. The PCA Forecast

As previously discussed, the forecast is now prepared from the Company's most recent Operating Plan (OP Plan). The OP Plan incorporates the most current information available in each update. An account by account breakdown of the Company's forecast proposal is shown on

Attachment C to these comments. The chart shows the amount included in Base Rates, the Forecast amount 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.

Lines 1 through 14 of page 1 of Attachment D show the Company's calculation of the Forecast Rate. Line 3 shows the expected reduction due to Hoku first block revenues and line 5 shows the customer sharing percentage that is applied to all power supply cost differences, except the difference in PURPA costs. Line 8, Column (g), shows the forecast rate excluding the portion of the forecast rate associated with the expected PURPA cost difference. This rate is 0.6451 ¢/kWh. Lines 10 through 12 show the calculation of the portion of the Forecast Rate associated with the expected difference in PURPA costs. This portion of the rate is negative because expected PURPA costs are less than PURPA costs included in base rates. This rate is -0.0789 ¢/kWh. The two portions of the forecast rate combined produce the forecast rate shown on line 14, 0.5662 ¢/kWh. Among other things, this rate reflects expected below normal water conditions. Under the new forecast methodology, Idaho Power does its own water forecast, however, the Northwest River Forecast Center expects April through July Brownlee Reservoir inflows to be 81% of normal.

Since the filing of this case the Company has updated its Operating Plan. Use of the updated plan reduces forecasted system power supply costs by approximately $10.7 million. The recalculated forecast rate of 0.4967 ¢/kWh is shown on page 2 of Attachment D, line 14.

Staff proposes that the Commission adopt a different Forecast Rate than those previously discussed in an effort to phase in the change in forecast methodology and to mitigate the large increase proposed by the Company in this case. As shown on page 3 of Exhibit D, Staff proposes a forecast rate of 0.2500 ¢/kWh. This rate is expected to recover approximately $34.6 million of the $68.0 million that the updated forecast would require. To the extent that this forecast rate under-recovers the difference between actual and normal power supply cost, the unrecovered costs will be captured in next year's true-up. Staff is very much aware that the true-up methodology was changed to improve the forecast and that a rate that does not reflect the improved forecast leaves money to be recovered the following year in the true-up just like a poor forecast would. However, Staff believes the size of the proposed increase and the size of the true up rate in place from a poor forecast last year justifies modifying the result for this year's PCA forecast. Also, the proposed increase is over the 7% threshold established by the Commission at which level spreading the increase over multiple years would be considered. Staff's proposal spreads the recovery of forecast costs over two years. The forecast proposed by the Company is the largest ever. The forecast proposed by Staff, produces the second largest forecast of record. This attests to the enhanced accuracy of the forecast methodology and the likelihood of a reduced true up next year.

B. The PCA True-Up

The PCA true-up captures the difference between normal and actual power supply costs adjusted by revenue from the forecast rate. Rates were set in the previous PCA period to collect or refund to customers the difference between the projected power supply costs and those costs reflected in rates. This difference is the PCA deferral balance. This deferral balance, when surcharged or refunded to customers is known as the PCA true-up rate component.

Exhibit No. 1 to Idaho Power witness Scott Wright's testimony illustrates the calculation of the true-up deferral amount. 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 the cloud seeding program, fuel expenses for coal, fuel expenses for natural gas, and power purchases and sales. Staff also examined the Emission Allowance Sales Credit and the Risk Management operating plan.

Attachment E is Staff's calculation of the true-up deferral amount before it is reduced by the Emission Allowance Sales Credit. A summary of the true-up is the following.

Idaho Jurisdictional Items	MILLIONS
Last Year's Forecast Revenue	$ (3.7)
Last Year's Above Normal Power Supply Costs (Shared)	$ 143.0
Last Year's Above Normal PURPA Facilities Costs	$ (33.9)
Interest	$ 2.5
True-up Expense (Deferral)	$ 107.9
Emission Allowance Sales Credit	$ (4.6)
Total True-up Deferral with Emission Allowance Sales Credit	$ 103.3

Staff's true-up recommendation differs slightly from Idaho Power's due to a small difference in the Emission Allowance Sales Credit discussed later in these comments. The following items are included in the PCA true-up.

1. Base Power Supply. During the past PCA year actual power supply costs have been measured against portions of three different base periods to determine deferral amounts. The first base was in place for April and May of 2008 (2 months), the second base was in place June 2008 through January 2009 (8 months) and the third base was in place during February and March of 2009 (2 months). In the Company's last PCA case the Commission approved redistribution of the monthly AURORA base amounts to average monthly amounts. The first two base periods in this true-up year used this distribution. The third base period in this true-up year also redistributed the AURORA base. For the third base period, the Company has been authorized to redistribute or shape base power supply costs according to the monthly distribution of Idaho Jurisdictional Revenues. Since monthly deferral amounts are a calculation of the difference between the actual power supply costs and base power supply costs, monthly deferral amounts differ because the base has been redistributed or reshaped. The net difference for the true-up year in this case is approximately $3.4 million to the customers' benefit. Monthly differences can be large and customers may not always benefit. Staff proposes to track the differences each year and to propose changes to the methodology if the differences becomes unacceptable.

2. SO2 Proceeds. Commission Order No. 30790 in Case Nos. IPC-E-09-08 and IPC-E-08-14 was issued on May 1, 2009 and ordered that $5,347,453 of Emission Allowance Sales ($5,299,875 plus accrued interest of $47,578 as of March 31, 2009) be used to offset the Company's PCA deferral balance this year. This is a system number. The amount used by the Company for the Emission Allowance sales credit is $4,591,632. This is the Idaho jurisdictional amount and includes interest through March 2009. As shown on page 3 of Attachment D, line 20 in the "Base" column of Staff's Recommendation, the SO2 credit amount with interest through May 31, 2009 is $4,600,857. The difference between the amounts used by the Company in its PCA filing and Staff's recommendation is due to interest on the SO2 credit balance for April and May 2009. The SO2 credit is a benefit to customers.

3. Cloud Seeding Program. Cloud seeding expenses have been recorded in the PCA since October 2006. In Case No. IPC-E-05-28, Order No. 30035, monthly cloud seeding expenses were incorporated into base rates. In this PCA period, the cloud seeding expense in base rates is $719,261. The actual amount of expense for the Cloud Seeding Program for the PCA period from April 2008 through March 2009 is $608,785. Actual expenses are less than the

expense in base rates by $110,476. This represents a benefit to customers and is subject to jurisdictional allocation and sharing.

4. 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 2008 to March 2009, the total coal expense for all plants in operation is $135,782,138. The total coal expense included in base rates is $112,483,839. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $23,298,299. This cost to customers is subject to jurisdictional allocation and sharing.

5. 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 2008 to March 2009 the total variable gas and gas transportation expense for both complexes was $15,196,631; down from $20,823,773 during the last PCA period. The total gas and gas transportation expense included in base rates is $11,108,299. 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 $4,088,322 and is subject to jurisdictional allocation and sharing.

6. Power Sales and Purchases. Staff reviewed the power purchases and sales in conjunction with the Company's Risk Management Operating Plans. Our 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, 2009, the Company sold surplus power totaling $107,888,656. The total surplus sales included in base rates is $124,387,177. 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 $16,498,521. This difference is a reduction of revenues to the detriment of customers and is subject to jurisdictional allocation and sharing.

b. Power Purchases including Telocaset and Raft River. Power purchases included in base rates are shown on Line 34, Attachment E. Market purchases, Telocaset Wind Power Partners, and Raft River (the shared portion) are combined in this base number. On the PCA spreadsheet, the actual amounts for these three purchase types are stated as separate line items.

During the PCA year ending March 31, 2009, the Company made market purchases, excluding PURPA contracts. The actual amount is $151,742,384.

Beginning in November 2007, Idaho Power began receiving power from Telocaset Wind Power Partners project. This wind project was included in base rates in the last general rate case, Case No. IPC-E-07-08, Order No. 30508. The actual amount included in this year's PCA is $13,720,772.

On October 5, 2007, Idaho Power Company filed an application requesting an accounting order authorizing the inclusion of all power supply expenses associated with the purchase of energy from Raft River Energy I LLC in the Power Cost Adjustment mechanism. The underlying Power Purchase Agreement (PPA) for 13 MW is pursuant to a company Request for Proposal for geothermal resources and is the initial agreement with the U.S. Geothermal, Inc. of what will total 45.5 MW of geothermal energy. In Order No. 30485, the Commission found that the Company's proposal to recover 100% of the Power Purchase Agreement-related costs through its Power Cost Adjustment mechanism to be acceptable only for the first 10 aMW of PPA generation, and that the remaining PPA generation is subject to the PCA treatment accorded non-PURPA projects, and therefore subject to sharing. The actual Raft River amount included for non-PURPA recovery (the shared amount) is $274,426. The remaining Raft River amount is included below in section 7.

The total power purchases, including market power, Telocaset Wind Power Partners and the portion of Raft River subject to sharing is $165,737,582 ($151,742,384 plus $13,720,772 plus $274,426). The total power purchases included in base rates is $40,862,142. Actual purchased power amounts exceed base amounts by $124,875,440. This difference is a cost to customers and is subject to jurisdictional allocation and sharing.

7. 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 2008 through March 2009 the actual QF expense is $46,967,783. The Raft River amount included in the true-up deferral balance at 100% recovery is $4,758,932. The total actual QF expense, including Raft River is $51,726,715. The QF expense included in base rates is $87,541,896. 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 less than the base QF by $35,815,181. This amount is a benefit to customers and reduces the PCA deferral balance. PURPA contracts are not currently subject to sharing. They are subject to jurisdictional allocation.

8. <u>Third Party Transmission</u>. 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 2008 to March 2009, the actual third party transmission expense is $790,343. The Third Party Transmission expense included in base rates is $1,650,586. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $860,243. Since 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.

9. Water Lease Purchases. The actual amount included in the balance for water lease purchases in the current PCA period is $2,391,740. This is an expense that does not occur in every PCA period. For example, in the last PCA period there were no water lease purchases. However, the PCA is the proper venue for recovery of water lease purchases. This expense is a cost to customers and is subject to jurisdictional allocation and sharing.

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

The PCA true-up of the true-up amount is the difference between what was anticipated 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. 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.

The true-up amount set for recovery in last year's PCA case (Case No. IPC-E-08-07) was approximately $124.1 million and the rate calculated to recover that amount from customers was 0.7504 ¢/kWh. With other adjustments and interest considerations, the approved rate under collected the true-up amount by $22.0 million. As shown on page 3 of Attachment D, line 23, this amount is used to calculate the true-up of the true-up PCA rate component of 0.1590 ¢/kWh. This is the same rate the Company calculated.

PCA RATES

The Staff's calculated PCA rate of 1.1554 ¢/kWh is the sum of the three components listed above (0.2500 + 0.7464 + 0.1590 = 1.1554). This rate is shown on page 3 of Attachment D, line 26. As previously discussed, Staff includes approximately one-half of the Company's updated forecast for the coming year and, therefore, proposes 0.2500 for the forecast rate. The true-up rate, 0.7464, is based on the true-up amounts included in the Company's filing with a small interest adjustment proposed by Staff. The true-up of the true-up rate, 0.1590, is the same rate included in the Company's filing. Staff Attachment F summarizes all PCA rate components and their associated expense amounts. 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.

Page 1 of Attachment G shows the proposed average increase above base rates by class and page 2 of Attachment G shows the proposed average increase above existing rates by class. Staff proposes that existing rates be increased by $50.5 million which produces an average increase to Idaho Power's customers of 6.14%. This compares to the Company's filed proposal to increase rates $93.8 million, approximately 11.4%. Attachment G shows the proposed increases for all customer classes. Staff's proposed increase for residential customers is 5.01%.

In both of these attachments the percentage increase to larger customers is substantially more than the average percentage increase. When power supply costs increase rates, larger customers receive larger than average percentage increases. This results because large customers have lower base rates than other customers and an equal cents/kWh increase makes a larger percentage difference to them than it does to smaller customers whose base rates are higher.

CONSUMER ISSUES

Idaho Power's PCA Application, filed on April 15, 2009, contained both the customer notice and press release. Staff reviewed them and determined that they complied with the notice requirements of IDAPA 31.21.02.102. The customer notice was mailed with Idaho Power's cyclical billings beginning April 24, 2009 and ending May 22, 2009. Customers had until May 14, 2009 to file comments.

An informational customer workshop was scheduled in Boise on May 5, 2009 at 7:00 p.m. No customers attended the meeting.

By May 13, 2009, thirty-four customers had sent comments to the Commission regarding the PCA. One-third of those who sent comments mentioned that water was seemingly plentiful this year and so did not understand why poor water was cited by Idaho Power as a major factor in its need to increase rates in this year's PCA filing. One-half of those commenting questioned why the current economic downturn was not a valid reason for the Commission to tell the Company "no" to any rate increases at this time.

PCA RECOMMENDATIONS

The Staff's recommendation differs substantially from the Company's in the amount of the forecast to be passed to customers in this year's PCA rates. In addition to the reasons for Staff's recommendation that have been previously given, Staff believes that the large true up rate that will almost certainly be put in place in this case will expire next year. Staff believes that it is probable that the remainder of the unrecovered forecast can be moved to next year's true up without a rate increase.

Staff recommends that a PCA rate of 1.1554 ¢/kWh be established by the Commission with an effective date of June 1, 2009.

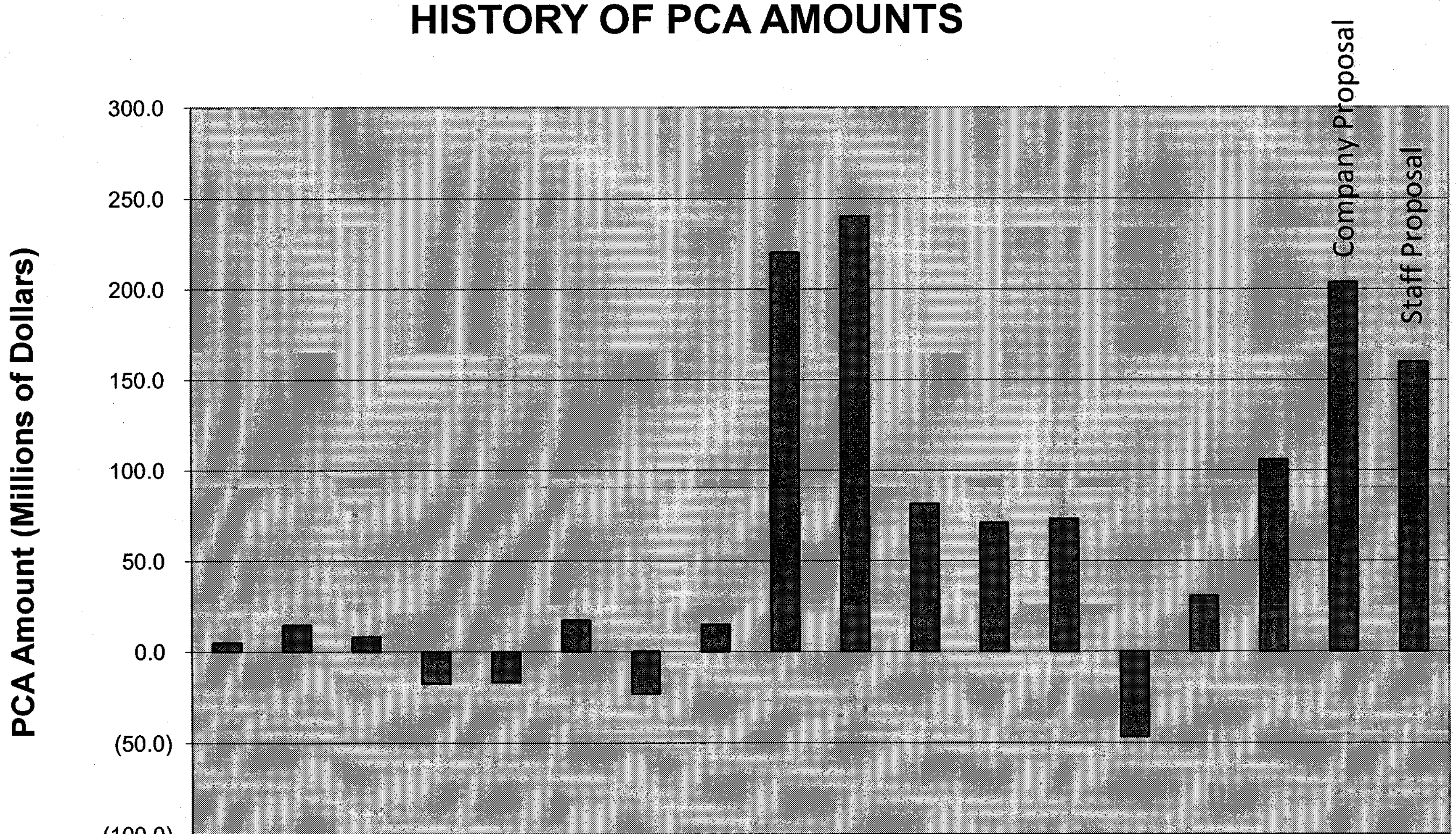
Respectfully submitted this 14th day of May 2009.

Weldon B. Stutzman
Deputy Attorney General

Technical Staff: Keith Hessing
Kathy Stockton
Marilyn Parker

i:umisc/comments/ipce09.11wskhklsmp comments

HISTORY OF PCA AMOUNTS

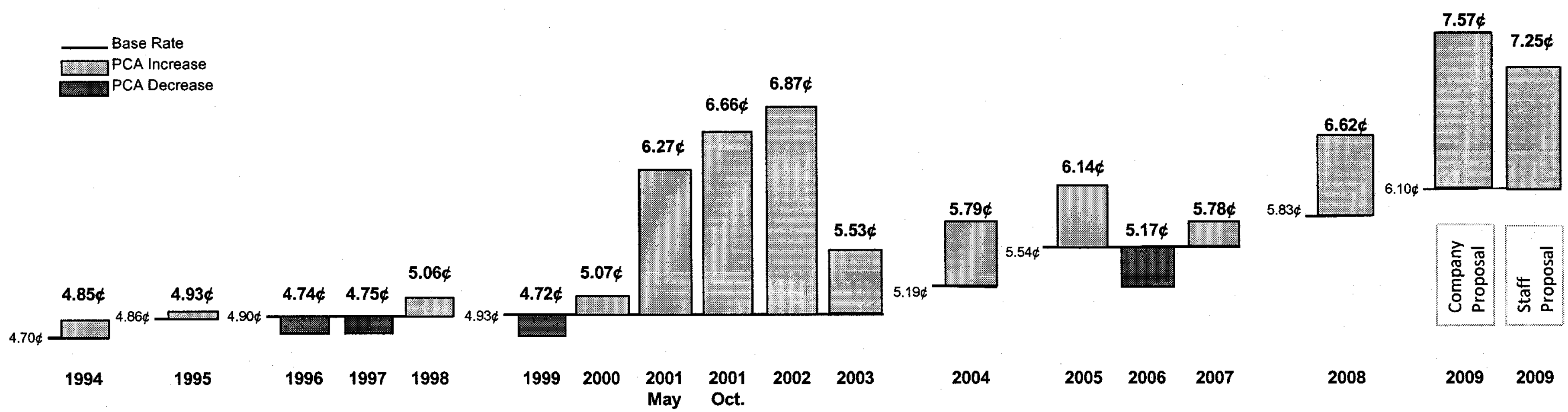


	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2009
■ PCA Amounts	4.9	14.7	8.1	(17.6	(16.7	17.3	(23.2	14.8	220.2	240.2	81.3	70.8	73.1	(46.8	30.7	106.0	203.7	159.9

PCA Year

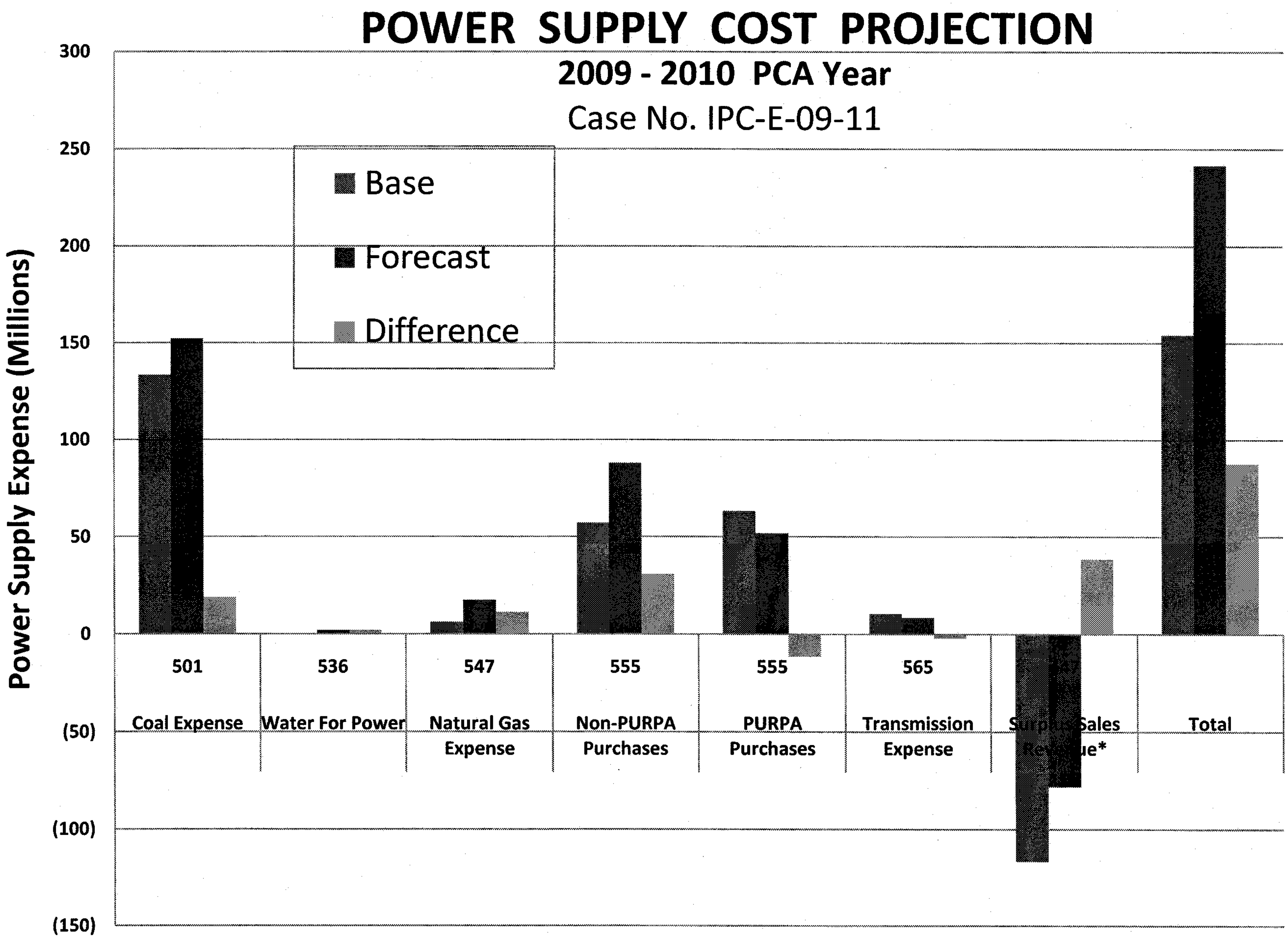
AVERAGE RESIDENTIAL ENERGY RATES FOR IDAHO POWER COMPANY

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.

U:\khessin\IPCE0911\PCA History Chart 5/13/2009 KDH



Attachment C
Case No. IPC-E-09-11
Staff Comments
05/14/09

2009-2010 PCA - Seventeenth Annual
IPC-E-09-11
Company Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Projection 2009-2010:**					
2	PCA Expense (95%)	($)	90,780,502	208,377,734		
3	Hoku First Block Revenue Reduction	($)		18,539,291		
4	Difference	($)		189,838,443	99,057,941	
5	Sharing Percentage	(%)			0.95	
6	Shared Difference	($)			94,105,044	
7	Normalized System Firm Sales	(MWH)			14,586,634	
8	Rate for 95 % Items	(¢/kWh)			0.6451	0.6451
9						
10	PCA Expense (100%)	($)	63,269,889	51,767,620	(11,502,269)	
11	Normalized System Firm Sales	(MWH)			14,586,634	
12	Rate for 100% Items	(¢/kWh)			(0.0789)	(0.0789)
13						
14	Total Forecast Rate	(¢/kWh)				**0.5662**
15						
16						
17			($)	(MWh)	($/MWh)	(¢/kWh)
18						
19	**True-Up of 2008-2009:**		107,891,769	13,838,689	7.796386565	0.7796
20	SO2 Credit (Case No. IPC-E-09-08)		(4,591,632)	13,838,689	-0.331796748	(0.0332)
21	Total		103,300,137			**0.7465**
22						
23	**True-Up of the True-Up:**		22,003,335	13,838,689	1.589986956	**0.1590**
24						
25	**PCA Rates:**					
26	PCA Rate Adjustment From Base	(¢/kWh)				**1.4717**
27	PCA Rate Currently in Effect	(¢/kWh)				0.7864
28	Difference - Last Year to This Year	(¢/kWh)				0.6853
29						
30	Note: Negative rates and amounts indicate benefits to ratepayers.					

2009-2010 PCA - Seventeenth Annual
IPC-E-09-11
Company Case with Updated OP Plan

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Projection 2009-2010:**					
2	PCA Expense (95%)	($)	90,780,502	197,692,328		
3	Hoku First Block Revenue Reduction	($)		18,539,291		
4	Difference	($)		179,153,037	88,372,535	
5	Sharing Percentage	(%)			0.95	
6	Shared Difference	($)			83,953,908	
7	Normalized System Firm Sales	(MWH)			14,586,634	
8	Rate for 95 % Items	(¢/kWh)			0.5756	0.5756
9						
10	PCA Expense (100%)	($)	63,269,889	51,767,620	(11,502,269)	
11	Normalized System Firm Sales	(MWH)			14,586,634	
12	Rate for 100% Items	(¢/kWh)			(0.0789)	(0.0789)
13						
14	Total Forecast Rate	(¢/kWh)				**0.4967**
15						
16						
17			($)	(MWh)	($/MWh)	(¢/kWh)
18						
19	**True-Up of 2008-2009:**		107,891,769	13,838,689	7.796386565	0.7796
20	SO2 Credit (Case No. IPC-E-09-08)		(4,591,632)	13,838,689	-0.331796748	(0.0332)
21	Total		103,300,137			**0.7465**
22						
23	**True-Up of the True-Up:**		22,003,335	13,838,689	1.589986956	**0.1590**
24						
25	**PCA Rates:**					
26	PCA Rate Adjustment From Base	(¢/kWh)				$\boxed{1.4022}$
27	PCA Rate Currently in Effect	(¢/kWh)				0.7864
28	Difference - Last Year to This Year	(¢/kWh)				0.6158
29						
30	Note: Negative rates and amounts indicate benefits to ratepayers.					

2009-2010 PCA - Seventeenth Annual
IPC-E-09-11
Staff Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Projection 2009-2010:**					
2	PCA Expense (95%)	($)	90,780,502	159,820,102		
3	Hoku First Block Revenue Reduction	($)		18,539,291		
4	Difference	($)		141,280,811	50,500,309	
5	Sharing Percentage	(%)			0.95	
6	Shared Difference	($)			47,975,293	
7	Normalized System Firm Sales	(MWH)			14,586,634	
8	Rate for 95 % Items	(¢/kWh)			0.3289	0.3289
9						
10	PCA Expense (100%)	($)	63,269,889	51,767,620	(11,502,269)	
11	Normalized System Firm Sales	(MWH)			14,586,634	
12	Rate for 100% Items	(¢/kWh)			(0.0789)	(0.0789)
13						
14	Total Forecast Rate	(¢/kWh)				**0.2500**
15						
16						
17			($)	(MWh)	($/MWh)	(¢/kWh)
18						
19	**True-Up of 2008-2009:**		107,891,769	13,838,689	7.796386565	0.7796
20	SO2 Credit (Order No. 30790)		(4,600,857)	13,838,689	-0.332463357	(0.0333)
21	Total		103,290,912			**0.7464**
22						
23	**True-Up of the True-Up:**		22,003,335	13,838,689	1.589986956	**0.1590**
24						
25	**PCA Rates:**					
26	PCA Rate Adjustment From Base	(¢/kWh)				**1.1554**
27	PCA Rate Currently in Effect	(¢/kWh)				0.7864
28	Difference - Last Year to This Year	(¢/kWh)				0.3690
29						
30	Note: Negative rates and amounts indicate benefits to ratepayers.					

TRUE-UP CALCULATIONS FOR 2008 - 2009
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-09-11

1			2008	2008	2008	2008	2008	2008	2008
2	DESCRIPTION	Units	APR	MAY	JUN	JUL	AUG	SEPT	OCT
3	**PCA Revenue**								
4	Normalized Idaho Jurisd. Sales	MWh	963,083	976,345	1,119,936	1,321,246	1,413,185	1,272,063	1,035,883
5	Forecast Rate	m/KWh	1.888	1.888	0.000	0.000	0.000	0.000	0.000
6	Revenue	$	1,818,301	1,843,339	0	0	0	0	0
7									
8	**Load Change Adjustment**								
9	Actual System Firm Load - Adjusted	MWh	1,118,663	1,332,870	1,472,374	1,765,357	1,628,972	1,268,631	1,115,235
10	Normalized Firm Load	MWh	1,099,424	1,224,099	1,426,753	1,702,096	1,588,393	1,247,908	1,130,773
11	Load Change	MWh	19,239	108,771	45,621	63,261	40,579	20,723	(15,538)
12	Expense Adjustment	$	(604,008)	(3,414,866)	(1,432,271)	(1,986,079)	(1,273,978)	(650,599)	487,816
13									
14	**Non-QF PCA**								
15	ACTUAL:								
16	Water Lease Purchases	$	0	0	0	0	1,080,695	1,108,842	(6,797)
17	Cloud Seeding Program	$	24,877	126,300	20,562	32,578	29,738	44,700	55,584
18	Fuel Expense - Coal	$	7,833,016	8,351,409	9,218,290	12,316,271	13,603,945	12,226,463	10,452,157
19	Fuel Expense - Danskin	$	795,176	523,859	980,515	1,848,884	2,764,934	2,525,520	651,098
20	Fuel Expense - Bennett Mountain	$	345,664	192	292,746	61,966	1,245,723	68,538	21,307
21	Non-Firm Purchases	$	8,746,377	15,471,139	9,038,922	24,467,254	21,546,747	10,351,039	8,032,251
22	Telocaset Wind Power Partners	$	722,694	840,326	1,172,124	1,615,081	1,238,395	722,368	1,156,550
23	Raft River 90%	$	9,927	20,317	0	0	0	23,424	34,159
24	Third Party Transmission	$							
25	Surplus Sales	$	(8,677,754)	(8,438,165)	(5,257,208)	(8,082,568)	(9,669,473)	(13,698,132)	(8,694,596)
26	Expense Adjustment	$	(604,008)	(3,414,866)	(1,432,271)	(1,986,079)	(1,273,978)	(650,599)	487,816
27	Sub-Total	$	9,195,968	13,480,511	14,033,679	30,273,387	30,566,726	12,722,162	12,189,529
28									
29	BASE:								
30	Fuel Expense - Coal	$	5,895,851	5,895,851	9,956,571	9,956,571	9,956,571	9,956,571	9,956,571
31	Fuel Expense - Danskin	$	201,811	201,811	532,587	532,587	532,587	532,587	532,587
32	Fuel Expense - Bennett Mountain	$	91,967	91,967	661,799	661,799	661,799	661,799	661,799
33	Third Party Transmission	$							
34	Non-Firm Purchases	$	729,244	729,244	3,797,607	3,797,607	3,797,607	3,797,607	3,797,607
35	Surplus Sales	$	(3,994,247)	(3,994,247)	(12,252,659)	(12,252,659)	(12,252,659)	(12,252,659)	(12,252,659)
36	Cloud Seeding Expense	$	62,270	62,270	74,340	74,340	74,340	74,340	74,340
37	Cloud Seeding Benefit	$	(117,779)	(117,779)	(118,945)	(118,945)	(118,945)	(118,945)	(118,945)
38	Sub-Total	$	2,869,118	2,869,118	2,651,300	2,651,300	2,651,300	2,651,300	2,651,300
39									
40	Change From Base	$	6,326,849	10,611,393	11,382,379	27,622,087	27,915,426	10,070,862	9,538,229
41	Emission Allowance Sales Credit	$	0	0	0	0	0	0	0
42	Sub-Total	$	6,326,849	10,611,393	11,382,379	27,622,087	27,915,426	10,070,862	9,538,229
43									
44	Deferral (Shared and Allocated)	$	5,392,374	9,044,090	9,701,202	23,542,305	23,792,317	8,583,396	8,129,432
45									
46	**QF Deferral**								
47	Actual (includes Net Metering)	$	2,265,467	4,220,848	6,252,968	7,018,593	6,117,259	4,459,879	3,415,233
48	Raft River 100%	$	264,768	317,768	398,539	406,222	488,600	398,661	411,525
49	Base	$	7,756,719	7,756,719	7,756,719	7,756,719	7,756,719	7,756,719	7,756,719
50									
51	Change From Base	$	(5,226,485)	(3,218,104)	(1,105,212)	(331,905)	(1,150,860)	(2,898,179)	(3,929,962)
52	Deferral (Allocated)	$	(4,949,481)	(3,047,544)	(1,046,636)	(314,314)	(1,089,865)	(2,744,576)	(3,721,674)
53									
54	**Total Deferral** (-6+41+48)	$	(1,375,408)	4,153,207	8,654,566	23,227,991	22,702,453	5,838,820	4,407,759
55									
56	**Principal Balances**								
57	Beginning Balance	$	0	(1,375,408)	2,777,799	11,432,365	34,660,356	57,362,809	63,201,629
58	Amount Deferred	$	(1,375,408)	4,153,207	8,654,566	23,227,991	22,702,453	5,838,820	4,407,759
59	Ending Balance	$	(1,375,408)	2,777,799	11,432,365	34,660,356	57,362,809	63,201,629	67,609,387
60									
61	**Interest Balances**								
62	Accrual thru Prior Month	$	0	440	(5,233)	(44,371)	3,440	147,929	389,780
63	Interest @ 5% per Year	$	0	(5,731)	11,574	47,635	144,418	239,012	263,340
64	Prior Month's Interest Adj.	$	440	58	(50,713)	176	71	2,840	(32)
65	Total Current Month Interest	$	440	(5,672)	(39,139)	47,811	144,489	241,852	263,308
66	Interest Accrued to Date	$	440	(5,233)	(44,371)	3,440	147,929	389,780	653,088
67	**Balance (True-Up & Interest)**	$	(1,374,968)	2,772,567	11,387,994	34,663,796	57,510,737	63,591,409	68,262,476
68									
69	**True-Up of the True-Up**								
70	True-Up Revenues (Collections)	$	529,379	554,444	3,944,458	11,411,725	11,485,090	10,337,799	8,225,629
71									
72	Beginning Balance	$	4,862,487	118,992,270	112,443,347	102,436,843	91,451,939	80,347,898	70,344,882
73	Adjustments:								
74	2007-08 PCA Transfer - ON 30563	$	124,101,211	0	0	0	0	0	0
75	Emmission Allowance - ON 30529	$	(9,937,989)	0	(6,503,462)	0	0	0	0
76	Correction for Change in Base	$	0	(6,463,350)	0	0	0	0	0
77	Sub-Total	$	119,025,709	112,528,920	105,939,886	102,436,843	91,451,939	80,347,898	70,344,882
78	Interest @ 5% per Year	$	495,940	468,871	441,416	426,820	381,050	334,783	293,104
79	Revenue Applied to Interest	$	495,940	468,871	441,416	426,820	381,050	334,783	293,104
80	Revenue Applied to Balance	$	33,439	85,573	3,503,042	10,984,905	11,104,041	10,003,016	7,932,525
81	**True-Up of the True-Up Balance**	$	118,992,270	112,443,347	102,436,843	91,451,939	80,347,898	70,344,882	62,412,357
82									
83	Note: Negative amounts indicate benefit to ratepayers								

TRUE-UP CALCULATIONS FOR 2008 - 2009
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-09-11

1			2008	2008	2009	2009	2009	
2	DESCRIPTION	Units	NOV	DEC	JAN	FEB	MAR	TOTALS
3	**PCA Revenue**							
4	Normalized Idaho Jurisd. Sales	MWh	979,253	1,077,805	1,164,548	1,126,968	1,050,386	13,500,701
5	Forecast Rate	m/KWh	0.000	0.000	0.000	0.000	0.000	
6	Revenue	$	0	0	0	0	0	3,661,640
7								
8	**Load Change Adjustment**							
9	Actual System Firm Load - Adjusted	MWh	1,114,596	1,347,176	1,320,346	1,138,662	1,148,734	15,771,616
10	Normalized Firm Load	MWh	1,173,167	1,370,562	1,323,448	1,184,072	1,181,622	15,652,317
11	Load Change	MWh	(58,571)	(23,386)	(3,102)	(45,410)	(32,888)	119,299
12	Expense Adjustment	$	1,838,837	734,203	97,387	1,209,268	875,807	(4,118,482)
13								
14	**Non-QF PCA**							
15	ACTUAL:							
16	Water Lease Purchases	$	0	69,000	140,000	0	0	2,391,740
17	Cloud Seeding Program	$	61,444	79,398	133,603	0	0	608,785
18	Fuel Expense - Coal	$	13,006,576	10,978,921	13,243,306	11,994,470	12,557,316	135,782,138
19	Fuel Expense - Danskin	$	484,053	839,095	255,231	155,487	297,782	12,121,634
20	Fuel Expense - Bennett Mountain	$	0	490,939	105,014	100,123	342,784	3,074,997
21	Non-Firm Purchases	$	9,473,727	23,680,009	10,059,449	6,255,708	4,619,761	151,742,384
22	Telocaset Wind Power Partners	$	1,217,317	1,713,806	828,367	1,551,481	942,263	13,720,772
23	Raft River 90%	$	47,280	56,565	44,961	37,794	0	274,426
24	Third Party Transmission	$				159,220	631,123	790,343
25	Surplus Sales	$	(4,910,636)	(12,847,951)	(8,360,403)	(6,018,465)	(13,233,304)	(107,888,656)
26	Expense Adjustment	$	1,838,837	734,203	97,387	1,209,268	875,807	(4,118,482)
27	Sub-Total	$	21,218,598	25,793,987	16,546,916	15,445,087	7,033,532	208,500,082
28								
29	BASE:							
30	Fuel Expense - Coal	$	9,956,571	9,956,571	9,956,571	10,914,656	10,124,913	112,483,839
31	Fuel Expense - Danskin	$	532,587	532,587	532,587	454,259	421,390	5,539,968
32	Fuel Expense - Bennett Mountain	$	661,799	661,799	661,799	46,692	43,313	5,568,331
33	Third Party Transmission	$				856,271	794,315	1,650,586
34	Non-Firm Purchases	$	3,797,607	3,797,607	3,797,607	4,680,739	4,342,058	40,862,142
35	Surplus Sales	$	(12,252,659)	(12,252,659)	(12,252,659)	(9,533,614)	(8,843,798)	(124,387,177)
36	Cloud Seeding Expense	$	74,340	74,340	74,340			719,261
37	Cloud Seeding Benefit	$	(118,945)	(118,945)	(118,945)			(1,187,118)
38	Sub-Total	$	2,651,300	2,651,300	2,651,300	7,419,003	6,882,191	41,249,830
39								
40	Change From Base	$	18,567,298	23,142,687	13,895,616	8,026,084	151,341	167,250,251
41	Emission Allowance Sales Credit	$	0	0	0	0	0	0
42	Sub-Total		18,567,298	23,142,687	13,895,616	8,026,084	151,341	167,250,251
43								
44	Deferral (Shared and Allocated)	$	15,824,908	19,724,512	11,843,234	7,227,529	136,283	142,941,582
45								
46	**QF Deferral**							
47	Actual (includes Net Metering)	$	2,858,837	3,020,493	2,740,686	2,358,238	2,239,284	46,967,783
48	Raft River 100%	$	476,488	491,282	419,932	380,527	304,621	4,758,932
49	Base	$	7,756,719	7,756,719	7,756,719	5,174,557	4,800,146	87,541,896
50								
51	Change From Base	$	(4,421,394)	(4,244,945)	(4,596,101)	(2,435,793)	(2,256,242)	(35,815,180)
52	Deferral (Allocated)	$	(4,187,060)	(4,019,963)	(4,352,507)	(2,308,888)	(2,138,691)	(33,921,198)
53								
54	**Total Deferral** (-6+41+48)	$	11,637,848	15,704,549	7,490,726	4,918,641	(2,002,408)	**105,358,743**
55								
56	**Principal Balances**							
57	Beginning Balance	$	67,609,387	79,247,235	94,951,784	102,442,511	107,361,152	
58	Amount Deferred	$	11,637,848	15,704,549	7,490,726	4,918,641	(2,002,408)	105,358,743
59	Ending Balance	$	79,247,235	94,951,784	102,442,511	107,361,152	105,358,743	
60								
61	**Interest Balances**							
62	Accrual thru Prior Month	$	653,088	933,061	1,263,257	1,658,845	2,085,687	
63	Interest @ 5% per Year	$	281,706	330,197	395,632	426,844	447,338	2,581,965
64	Prior Month's Interest Adj.	$	(1,733)	(0)	(45)	(2)	0	(48,940)
65	Total Current Month Interest	$	279,972	330,196	395,588	426,842	447,338	2,533,025
66	Interest Accrued to Date	$	933,061	1,263,257	1,658,845	2,085,687	2,533,025	
67	**Balance (True-Up & Interest)**	$	80,180,296	96,215,042	104,101,356	109,446,839	107,891,769	**107,891,769**
68								
69	**True-Up of the True-Up**							
70	True-Up Revenues (Collections)	$	7,443,790	8,294,817	9,233,397	8,568,835	7,837,555	87,866,917
71								
72	Beginning Balance	$	62,412,357	55,228,619	47,163,921	38,127,041	29,717,069	4,862,487
73	Adjustments:							
74	2007-08 PCA Transfer - ON 30563	$	0	0	0	0	0	124,101,211
75	Emmission Allowance - ON 30529	$	0	0	0	0	0	(16,441,450)
76	Correction for Change in Base	$	0	0	0	0	0	(6,463,350)
77	Sub-Total	$	62,412,357	55,228,619	47,163,921	38,127,041	29,717,069	106,058,897
78	Interest @ 5% per Year	$	260,051	230,119	196,516	158,863	123,821	
79	Revenue Applied to Interest	$	260,051	230,119	196,516	158,863	123,821	3,811,355
80	Revenue Applied to Balance	$	7,183,738	8,064,698	9,036,880	8,409,972	7,713,734	84,055,562
81	**True-Up of the True-Up Balance**	$	55,228,619	47,163,921	38,127,041	29,717,069	22,003,335	**22,003,335**
82								
83	Note: Negative amounts indicate benefit to ratepayers							

Division of Power Costs
IPC-E-09-11
Company Case

Description	Initial Amount ($)	Allocated to Other Jurisdictions ($)	Shared with Shareholders ($)	Idaho Customer Revenue Requirement ($)	**Idaho PCA Rates (¢/kWh)**
Forecast (2009-2010)					
Non-QF Power Supply Cost Difference	99,057,941	5,160,919	4,694,851	89,202,171	
QF Power Supply Cost Difference	(11,502,269)	(599,268)		(10,903,001)	
Sub-Total	87,555,672	4,561,651	4,694,851	78,299,170	**0.5662**
True Up (2008-2009)					
Revenue from Forecast Rate	(3,661,640)			(3,661,640)	
Non-QF Power Supply Cost Difference	171,368,733	9,077,060	15,940,420	146,351,253	
Load Growth Adjustment	(4,118,482)	(220,156)	(488,655)	(3,409,671)	
QF Power Supply Cost Difference	(35,815,180)	(1,893,982)	0	(33,921,198)	
Interest During Deferral Period	2,533,025			2,533,025	
Sub-Total	130,306,456	6,962,922	15,451,766	107,891,769	
Emission Allowance Credit (IPC-E-09-08)	(4,591,632)			(4,591,632)	
Sub-Total	125,714,824	6,962,922	15,451,766	103,300,137	**0.7465**
True Up of the True Up					
Amount Carried Forward	4,862,487			4,862,487	
Other Limited Term Adjustments:					
2007-08 PCA Transfer - ON 30563	124,101,211			124,101,211	
Emmission Allowance - ON 30529	(16,441,450)			(16,441,450)	
Correction for Change in Base	(6,463,350)			(6,463,350)	
Interest During Amortization	3,811,355			3,811,355	
Collections from True Up Rate	(87,866,917)			(87,866,917)	
Sub-Total	22,003,335	0	0	22,003,335	**0.1590**
Total Power Cost Adjustment (PCA)	235,273,832	11,524,572	20,146,617	203,602,642	$\boxed{1.4717}$

Division of Power Costs
IPC-E-09-11
Staff Case

Description	Initial Amount ($)	Allocated to Other Jurisdictions ($)	Shared with Shareholders ($)	Idaho Customer Revenue Requirement ($)	**Idaho PCA Rates (¢/kWh)**
Forecast (2009-2010)					
Non-QF Power Supply Cost Difference	50,500,309	2,631,066	2,393,462	45,475,781	
QF Power Supply Cost Difference	(11,502,269)	(599,268)		(10,903,001)	
Sub-Total	38,998,040	2,031,798	2,393,462	34,572,780	**0.2500**
True Up (2008-2009)					
Revenue from Forecast Rate	(3,661,640)			(3,661,640)	
Non-QF Power Supply Cost Difference	171,368,733	9,077,060	15,940,420	146,351,253	
Load Growth Adjustment	(4,118,482)	(220,156)	(488,655)	(3,409,671)	
QF Power Supply Cost Difference	(35,815,180)	(1,893,982)	0	(33,921,198)	
Interest During Deferral Period	2,533,025			2,533,025	
Sub-Total	130,306,456	6,962,922	15,451,766	107,891,769	
Emission Allowance Credit (IPC-E-09-08)	(4,600,857)			(4,600,857)	
Sub-Total	125,705,599	6,962,922	15,451,766	103,290,912	**0.7464**
True Up of the True Up					
Amount Carried Forward	4,862,487			4,862,487	
Other Limited Term Adjustments:					
2007-08 PCA Transfer - ON 30563	124,101,211			124,101,211	
Emmission Allowance - ON 30529	(16,441,450)			(16,441,450)	
Correction for Change in Base	(6,463,350)			(6,463,350)	
Interest During Amortization	3,811,355			3,811,355	
Collections from True Up Rate	(87,866,917)			(87,866,917)	
Sub-Total	22,003,335	0	0	22,003,335	**0.1590**
Total Power Cost Adjustment (PCA)	186,706,975	8,994,720	17,845,228	159,867,027	$\boxed{1.1554}$

IPC-E-09-11
Idaho Power Company
Summary of Revenue Impact
State of Idaho
Normalized 12-Months Ending December 31, 2008
STAFF CASE
Base Rates to 6/1/09 PCA

Line No	Tariff Description	(1) Rate Sch. No.	(2) 2008 Avg. Number of Customers	(3) 2008 Sales Normalized (kWh)	(4) 04/01/09 Base Revenue	(5) 06/01/09 PCA Adjustment	(6) Total Revenue	(7) Average ¢/kWh	(8) Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1	391,376	5,062,831,148	327,482,769	58,495,951	385,978,720	7.624	17.86%
2	Residential Service Energy Watch	4	62	965,866	61,481	11,160	72,641	7.521	18.15%
3	Residential Service Time-of-Day	5	87	1,289,934	82,243	14,904	97,147	7.531	18.12%
4	Small General Service	7	31,171	190,586,226	15,488,243	2,202,033	17,690,276	9.282	14.22%
5	Large General Service	9	26,848	3,601,578,430	163,765,134	41,612,637	205,377,771	5.702	25.41%
6	Dusk to Dawn Lighting	15	-	5,957,094	1,004,323	68,828	1,073,151	18.015	6.85%
7	Large Power Service	19	111	2,123,608,415	74,487,285	24,536,172	99,023,457	4.663	32.94%
8	Agricultural Irrigation Service	24	15,484	1,551,322,661	81,668,256	17,923,982	99,592,238	6.420	21.95%
9	Unmetered General Service	39	0	0	0	0	0	0.000	0.00%
10	Unmetered General Service	40	1,855	16,739,169	966,323	193,404	1,159,727	6.928	20.01%
11	Street Lighting	41	140	22,084,297	2,314,258	255,162	2,569,420	11.635	11.03%
12	Traffic Control Lighting	42	220	4,207,305	164,514	48,611	213,125	5.066	29.55%
13	*Total Uniform Tariffs*		467,354	12,581,170,545	667,484,829	145,362,844	812,847,673	6.461	21.78%
	Special Contracts:								
14	Micron	26	1	703,404,640	21,204,238	8,127,137	29,331,375	4.170	38.33%
15	J R Simplot	29	1	189,569,677	5,319,281	2,190,288	7,509,569	3.961	41.18%
16	DOE	30	1	215,000,001	6,177,935	2,484,110	8,662,045	4.029	40.21%
17	*Total Special Contracts*		3	1,107,974,318	32,701,454	12,801,535	45,502,989	4.107	39.15%
18	***Total Idaho Retail Sales***		467,357	13,689,144,863	700,186,283	158,164,379	858,350,662	6.270	22.59%

IPC-E-09-11
Idaho Power Company
Summary of Revenue Impact
State of Idaho
Normalized 12-Months Ending December 31, 2008
STAFF CASE

4/1/09 All Current Revenue to 6/1/09 PCA

Line No	Tariff Description	(1) Rate Sch. No.	(2) 2008 Avg. Number of Customers	(3) 2008 Sales Normalized (kWh)	(4) 04/01/09 All Current Revenue	(5) 06/01/09 PCA Adjustment	(6) Total Revenue	(7) Average ¢/kWh	(8) Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1	391,376	5,062,831,148	373,170,229	18,681,847	391,852,076	7.740	5.01%
2	Residential Service Energy Watch	4	62	965,866	70,172	3,564	73,736	7.634	5.08%
3	Residential Service Time-of-Day	5	87	1,289,934	93,854	4,760	98,614	7.645	5.07%
4	Small General Service	7	31,171	190,586,226	17,287,121	703,263	17,990,384	9.439	4.07%
5	Large General Service	9	26,848	3,601,578,430	196,182,075	13,289,824	209,471,899	5.816	6.77%
6	Dusk to Dawn Lighting	15	-	5,957,094	1,076,278	21,982	1,098,260	18.436	2.04%
7	Large Power Service	19	111	2,123,608,415	93,049,524	7,836,115	100,885,639	4.751	8.42%
8	Agricultural Irrigation Service	24	15,484	1,551,322,661	95,909,564	5,724,381	101,633,945	6.551	5.97%
9	Unmetered General Service	39	0	0	0	0	0	0.000	0.00%
10	Unmetered General Service	40	1,855	16,739,169	1,122,118	61,768	1,183,886	7.073	5.50%
11	Street Lighting	41	140	22,084,297	2,545,785	81,491	2,627,276	11.897	3.20%
12	Traffic Control Lighting	42	220	4,207,305	201,713	15,525	217,238	5.163	7.70%
13	*Total Uniform Tariffs*		467,354	12,581,170,545	780,708,433	46,424,520	827,132,953	6.574	5.95%
	Special Contracts:								
14	Micron	26	1	703,404,640	27,265,918	2,595,563	29,861,481	4.245	9.52%
15	J R Simplot	29	1	189,569,677	6,943,039	699,512	7,642,551	4.032	10.08%
16	DOE	30	1	215,000,001	8,023,143	793,350	8,816,493	4.101	9.89%
17	*Total Special Contracts*		3	1,107,974,318	42,232,100	4,088,425	46,320,525	4.181	9.68%
18	***Total Idaho Retail Sales***		467,357	13,689,144,863	822,940,533	50,512,945	873,453,478	6.381	6.14%

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 14TH DAY OF MAY 2009, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-09-11 BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

DONOVAN E WALKER
BARTON L KLINE
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-MAIL: dwalker@idahopower.com
bkline@idahopower.com

SCOTT WRIGHT
GREGORY W SAID
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-MAIL: swright@idahopower.com
gsaid@idahopower.com

Jo Nelson
SECRETARY