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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, 2008 THROUGH MAY 31, 2009.	**CASE NO. IPC-E-08-7** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Donald L. Howell, II, Deputy Attorney General, respectfully submits the following comments in response to Order No. 30540 issued on April 25, 2008.

THE PCA APPLICATION

1. Background

On April 15, 2008, Idaho Power Company filed its annual power cost adjustment (PCA) Application. Since 1993, the PCA mechanism has permitted Idaho Power to adjust its PCA rates upward or downward to reflect the Company's annual "power supply costs." In a normal year about half of the Company's generation is from hydropower facilities. Idaho Power's actual cost of providing electricity (its power supply cost) varies from year to year depending on changes in Snake River streamflows, the market price of power, and other factors. The annual PCA surcharge or credit is combined with the Company's "base rates" to produce a customer's overall energy rate.

In this PCA Application Idaho Power requests recovery of $119.7 million of above normal power supply costs. This represents a 12.8 percent, $87.1 million increase above existing PCA rates.

2. The Deviation

In its filing the Company proposes a "one-year deviation" from the Commission-approved 90/10 "sharing" of abnormal power supply costs. The Company proposes that the entire variation be assigned to customers. For the remainder of this PCA year, the Company is requesting that all deviations in net power supply and PURPA project expenses be recoverable "at 100 percent for both forecast and true-up purposes." Said Dir. at 6. Under the Company's proposed 100% alternative, the forecast rate component would represent a decrease of 0.1314 ¢/kWh. Schwendiman Dir. at 9. The traditional 90% amount would be a decrease of 0.1183 ¢/kWh. Application at ¶ 7; Schwendiman Dir. at 4-5. If approved, the Company's proposal to not share the forecast cost savings would result in a one-time credit to customers of $1.8 million more than the traditional 90/10 sharing. However, neither the Staff nor the Company can determine the impact of not sharing next year's true up because the impact cannot be completely known until the end of the true-up period next March. The amount deferred for next year's true up could either increase or decrease customer rates.

The prefiled testimony of Company witness Greg Said recites several reasons to justify the "one-year deviation from the standard 90% - 10% sharing of PCA costs." Said Dir. at 6. He asserts that it would be appropriate for the Commission to allow 100% tracking of net power supply and PURPA project expenses in this PCA year based upon the "persistent drought conditions [in recent years], the lack of inclusion of prescriptive hedging activities in PCA forecast methodology, and the failure of a number of PURPA projects to come on-line as envisioned in the last approved test year." *Id.* at 9.

3. SO2 Credits

On April 14, 2008, the Commission issued Order No. 30529 in the sulfur dioxide (SO2) case, No. IPC-E-07-18. In Order No. 30529 the Commission directed that the majority of SO2 revenue that Idaho Power received in 2007 from the sale of SO2 emission allowances be included in this year's PCA case. The SO2 proceeds of about $16.5 million will reduce the PCA deferral balance. Given the timing of the SO2 Order, Idaho Power's PCA Application did not include the $16.5 million PCA cost reduction from SO2 proceeds. Application at ¶ 18.

If Idaho Power's PCA filing is adjusted to include SO2 proceeds, Idaho Power calculates that its annual power costs remain above existing PCA rates. To recover the increased power costs, the

Company estimates that the existing PCA rates must increase about $70.7 million, or an average increase in the existing PCA rates of approximately 10.36%.

4. Tariff Format

The Company also proposes an administrative change to its Tariff format. The Company would no longer show the PCA rate on each schedule, but would reference all schedules, by schedule number, that could adjust customer rates.

Attachment A to these comments is a chart that shows the magnitude of the PCA for each year since its inception in 1993. For 2008 both the Company and Staff proposals are shown and both include revenue from the sale of SO2 allowances. 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 with revenue included for SO2 allowance sales.

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

The National Weather Service Northwest River Forecast Center in Portland, Oregon forecasts the April through July Brownlee Reservoir inflow this year to be 5.40 million acre-feet (maf). This is slightly more than the 5.39 maf average (1928 – 2005). A regression equation developed from the results of a power supply model run is used to forecast "Net Power Supply Costs." *See* Order No. 24806 and Staff Attachment C. Using the forecasted 5.40 maf and the regression equation, Staff calculates Net Power Supply Costs for April 2008 through March 2009, to be $16,255,624. As authorized by Commission Order, Staff increased the calculated Net Power Supply Costs by expected PURPA qualifying facility purchases of $93,080,631 and reduced the amount by the expected net benefit of cloud seeding $535,250 ($892,084-1,427,334) to generate an expected PCA expense of $108,801,005. This is approximately $18.7 million below normal power supply cost levels on a total Company basis. Staff found that its calculation agreed with Idaho Power's calculation. The calculation of the forecast rate component is shown on lines 1 through 7 of Attachment D. The Company's forecast rate component calculation is shown on Line 6 to be -0.1183 ¢/kWh. Staff's calculation of the forecast rate component agrees with Idaho Power's calculation when the abnormal costs are not shared but assigned 100% to ratepayers.

However, Staff recommends that 90/10 sharing be continued. Sharing is an extremely important part of the PCA. It is a type of Performance Based Ratemaking (PBR) that aligns the interests of shareholders and ratepayers. It keeps the Company economically involved in power supply decisions. As previously cited, Company witness Said points to drought, prescriptive risk management policy and the failure of several PURPA projects to come on-line to support his no sharing (100/0) proposal. It is true that the Company has little control over drought, but the Company has found a way to reduce drought impacts. The Company seeds clouds and to the extent that the practice causes more water to be available to generate power the shareholders get to keep 10% of the cost savings. Without an economic interest in cloud seeding results the Company may not have worked through the process to obtain Commission approval for the program.

It is also true that the Company's Risk Management Program has made market purchases and sales more prescriptive. The Risk Management Program was largely developed by the Company and its consultant to address high power supply costs that were assigned to shareholders in the 2000 – 2003 timeframe as a direct result of PCA sharing. The Company had an economic interest in addressing the concern and took the lead. The Company's current risk management strategy is not set in stone. It continues to evolve and improve. Improvements that economically benefit shareholders continue to benefit ratepayers. If ratepayers were responsible for all abnormal power supply costs this simply would not be true. Sharing keeps the Company actively engaged in the risk management process.

Finally, it is also true that some of the PURPA projects included in the Company's last general rate case (IPC-E-07-8) that were expected to be online near the end of 2007 are not yet online or even under construction. This causes two separate economic impacts in the PCA. First, base rates include contract purchase costs that the Company is not paying. The current PCA fairly addresses this by returning these base costs that are not incurred to ratepayers. All PURPA cost savings go 100% to ratepayers. Second, the inclusion of PURPA energy in the base power supply cost calculations reduces base purchased power costs, base fuel costs and increases base secondary sales revenues. These power supply cost savings do not materialize when projects remain incomplete. In the PCA true up, PURPA energy not delivered may be replaced by higher cost energy purchases. Therefore, the true up includes higher than normal power supply costs for which shareholders only receive 90% reimbursement. The end result is that the Company refunds to ratepayers 100% of the PURPA contract costs that the Company does not have to pay but does not get to pass 100% of the replacement power costs on to customers. The Company's solution is to not share power supply costs so that shareholders are 100% reimbursed for these costs. However in Staff's opinion, the Company's solution leaves it with no economic incentive to resolve what is becoming a very large problem of PURPA developers with signed contracts not delivering.

It is interesting that the inequity that the Company is attempting to solve by eliminating sharing is the mirror image of a customer inequity that also exists because sharing percentages are different for PURPA power supply costs (100/0) than they are for other power supply costs (90/10). The more common situation is for PURPA contracts to come online between rate cases when the contracts are not included in base rates. When this occurs, 100% of the contract costs are passed on to ratepayers but ratepayers only receive credit for 90% of the benefits. This is also not fair and is the flip side of the problem the Company is trying to address. There is balance in keeping sharing percentages the way they currently are. Under one scenario customers benefit and under the other scenario shareholders benefit.

In this case Staff continues to recommend that PURPA costs not be shared and that other power supply costs be shared 90/10 between ratepayers and shareholders. Staff also recommends that this aspect of sharing be discussed in workshops following this case. Once again sharing is important. Sharing maintains the Company's economic interest in addressing the problem of PURPA contracts that do not even come close to meeting their online dates.

Staff recommends 90/10 sharing of all non-PURPA power supply costs. Sharing provides economic incentive for the Company to address drought, to improve risk management policies and to improve power supply contractor performance.

Although the Staff calculates the same forecast rates, with and without sharing, that the Company does, the Staff recommends that this years power supply cost forecast be assumed to be normal. This means that the forecast rate would be zero. Staff makes this recommendation for two reasons. Forecast Brownlee inflow is very near normal Brownlee inflow at 5.40 maf versus 5.39 maf, respectively. While Staff believes that the cost forecast is much improved over those of the recent past, we recognize that actual costs will deviate from the forecast for a variety of reasons. It is counter productive to return money to ratepayers based on a forecast that may prove to be inaccurate and then have to put an increased true-up rate in place the following year that recovers the money previously given back. The Company has suggested workshops following this case to discuss various elements of the PCA. The Staff also recommends such workshops. The Staff believes that it is appropriate to discuss whether or not relatively small rate decreases should be passed on to customers in a forecast rate or whether it is better to wait until power supply cost savings actually occur and capture those savings in the true up.

B. The PCA True Up

The PCA true up captures the difference between the projected power supply costs from the past PCA year and the actual power supply costs that the Company incurred during that same year. 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. The differences between projected power supply costs and actual power supply costs 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. 3 to Idaho Power witness Schwendiman'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 all 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. Staff's true-up recommendation differs from Idaho Power's in two areas, the distribution of base power supply costs and the Emission Allowance Sales Credit. The following items are included in the PCA true up.

1. Base Power Supply. Staff recommends a different distribution of the base power supply costs in the PCA deferral and true-up calculations. This issue was identified due to its impact on earnings. The Staff recommendation has been discussed with the Company. The recommendation impacts the March deferral in this PCA year and all months in the next PCA year. There are several reasons for this recommended change. They include the following: The distribution changed significantly in the 2007 test year underlying the settlement of base power supply costs in Case No. IPC-E-07-8. This change will result in a significant shift in Company earnings between quarters and in monthly PCA deferrals compared to historical levels. The distribution is important in rate cases to establish the annual power supply dollar cost using the AURORA model for base rates. Although the annual total power supply cost remains the same, use of the more volatile distribution in the PCA significantly shifts the level of deferrals between months beginning in March 2008 from that experienced in prior PCA years. Staff recommends a flat distribution with the issue evaluated as one of the PCA agenda items in the proposed upcoming workshops. In this PCA year the impact will be a lower PCA deferral for March 2008. Deferrals in the next PCA year will also differ with the spring months continuing to reflect lower PCA deferrals and the summer months reflecting higher deferrals but maintaining the same annual base power supply cost. The level distribution for the PCA deferral reduces earnings volatility and minimizes arguments to eliminate the 90/10 sharing.

2. SO2 Proceeds. As shown on page 2 of Attachment E, line 63 in the "Totals" column, the true-up amount with interest is $117,637,863. The true-up amount used by the Company to calculate the true-up rate did not include the Emission Allowance sales credit of approximately $16.5 million. This amount is not included in Company Exhibit No. 3 or Staff Attachment E since they reflect PCA items through March 2008 and Order No. 30529 on the Emission Allowance Sales Credit issued in Case No. IPC-E-07-18 on April 14, 2008. Order No. 30529 reserves $500,000 for Commission decision related to the Idaho Energy Education Project's request. The total Idaho jurisdictional sales credit of $16,635,022 includes the Idaho Tax reserve of $6,503,462. These Idaho amounts reduced by the $500,000 reserve and increased by interest through May 2008 of $390,859 results in $16,525,880 to be deducted from this PCA for the Emission Allowance sales credit.

In rounded numbers, the true-up amount is composed as shown below with the Emission Allowance sales credit included as a separate line item.

Idaho Jurisdictional Items	MILLIONS
Last Year's Forecast Revenue	$ (15.9)
90 % of Last Year's Above Normal Power Supply Costs	$ 144.2
Last Year's Above Normal PURPA Facilities Costs	$ (14.1)
Interest	$ 3.4

True-up Expense (Deferral)	$ 117.6
Emission Allowance Sales Credit	$(16.5)

Total True-up Deferral with Emission Allowance Sales Credit	$ 101.1

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 $899,385. The actual amount of expense for the Cloud Seeding Program for the PCA period from April 2007 through March 2008 is $798,817. Actual expenses are less than the expense in base rates by

$100,568. This represents a benefit to customers and is subject to jurisdictional allocation and 90/10 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 2007 to March 2008, the total coal expense for all plants in operation is $119,443,355. The total coal expense included in base rates is $93,724,743. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $25,718,612. This cost to customers is subject to jurisdictional allocation and 90/10 sharing.

5. Fuel Expense – Gas. Idaho Power currently owns and operates two gas-fired combustion turbine generating plants at the Evander Andrews Power Complex (Danskin units) and Bennett Mountain. These plants are both located at Mountain Home and account for 100% of gas usage. Actual generation from natural gas is up by 198% over the previous PCA period (roughly three times the amount of power was generated in this PCA period versus the last PCA period), while the increase in the actual amount spent for natural gas is up by 155% over the previous PCA period. Last year's low water may be one reason why the production at these two plants almost tripled during this PCA period versus the last PCA period. However, there are other factors, such as increased electricity demand and running the plants not only for peak usage, but for off-system sales to the extent the plants are "in the money", which would also help explain the increased usage of these gas fired units.

For the audit period of April 2007 to March 2008 the total variable gas and gas transportation expense for both plants was $20,823,773; up from $8,181,907 during the last PCA period. The total gas and gas transportation expense included in base rates is $4,707,578. 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 gas expense that is included for future recovery from customers is $16,116,195 and is subject to jurisdictional allocation and 90/10 sharing.

The recommendations in Case No. IPC-E-08-1, the addition of the new 170-MW Danskin 1 unit at the Evander Andrews Power Complex in Mountain Home, increases the gas fuel costs in the base rates. This update of power supply costs should reduce the true-up amount for gas in the next PCA.

6. Power Purchases and Sales. During the PCA year ending March 31, 2008, the Company sold surplus power totaling $123,157,730. The total surplus sales included in base rates is $60,273,647. 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 90/10 sharing. Actual surplus sales exceeded base amounts by $62,884,083. This difference is a benefit to customers and is subject to jurisdictional allocation and 90/10 sharing.

During the PCA year ending March 31, 2008, the Company made total power purchases, excluding PURPA contracts, of $233,485,572. The total power purchases included in base rates is $12,420,544. Actual purchased power amounts exceed base amounts by $221,065,028. This difference becomes a cost to customers and is subject to jurisdictional allocation and 90/10 sharing.

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.

7. Telocaset Wind Power Partners. Beginning in November 2007, Idaho Power began receiving power from this wind project. Because the project came online during the middle of the PCA period, the Company stated it separately as a line item in the PCA deferral calculation. This wind project was included in base rates in the last general rate case, IPC-E-07-8, Order No. 30508. The new base rates from this case are included in the base rates for the month of March 2008. The amount included in this year's PCA deferral is $3,676,418. The costs for this project are subject to jurisdictional allocation and 90/10 sharing.

8. Actual Qualifying Facilities Purchases including Net Metering. 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.

Idaho Power has many contracts with qualifying facilities. For the audit period of April 2007 through March 2008 the actual QF expense is $45,143,614. The QF expense included in base rates is $60,081,272. 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 $14,937,659. This amount is a benefit to customers and reduces the PCA deferral balance. PURPA contracts are not currently subject to the 90/10 sharing. They are subject to jurisdictional allocation.

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 the true up was set and what was actually collected or refunded. When special adjustments are not carried into the true up of the true-up calculation, 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 (IPC-E-07-10) was $15,090,267 and the rate calculated to return that amount to customers was 0.1120 ¢/kWh. With other adjustments and interest considerations, the approved rate under collected the true-up amount by $4,862,487. As shown on Attachment D, line 15, this amount is used to calculate the true up of the true-up PCA rate component of 0.0361 ¢/kWh. This is the same rate the Company calculated.

PCA RATES

The Staff's calculated PCA rate of 0.7864 ¢/kWh is the sum of the three components listed above (0.0000 + 0.7504 + 0.0361 = 0.7864). This rate is shown on Attachment D, line 18. As previously discussed, Staff assumes normal power supply costs for the coming year and, therefore, includes 0.0000 for the forecast rate. The true-up rate, 0.7504, is based on the true-up amounts included in the Company's filing with the additional adjustments of a credit for the sale of SO2 allowances and the levelization of March base power supply costs as previously discussed. The true up of the true-up rate, 0.0361, is the same rate included in the Company's filing. Staff Attachment F summarizes all PCA rate components and their associated expense amounts. It also shows amounts allocated to other jurisdictions and amounts shared with shareholders.

Attachment G shows the proposed average increase above base rates by class and Attachment H shows the proposed average increase above existing rates by class (last year's PCA rates to this year's PCA rates). Staff proposes that existing rates be increased by $73.3 million which produces and average increase to Idaho Power's customers of 10.7%. This compares to the Company's filed proposal to increase rates $87.1 million, 12.8% without the SO2 credits.

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 smaller customers and an equal cents-per-kWh increase makes a larger percentage difference to them than it does to smaller customers whose base rates are higher.

TARIFF MODIFICATION

The Company also proposes an administrative change to its tariff format. The change would remove the PCA rate currently shown on each schedule where it applies, but then reference Schedule 55 where the PCA rate is shown along with any other schedules that may also impact the rates customers on that schedule pay. Some of these other schedules would be the BPA Residential Exchange Schedule, the Energy Efficiency Rider and the Municipal Franchise Fee Schedule. One advantage of the proposed change is that the Company would not have to refile all schedules every time the PCA rates change. The Staff supports the tariff change proposed by the Company.

CONSUMER ISSUES

Idaho Power's PCA Application, filed on April 15, 2008, 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 25, 2008 and ending May 23, 2008. Customers had until May 20, 2008 to file comments.

Informational customer workshops were scheduled in Pocatello, Twin Falls and Boise. Three customers attended in Pocatello; there were no customers who attended the Twin Falls and Boise meetings.

PCA RECOMMENDATIONS

Staff has the following PCA recommendations:

- Staff recommends that 90/10 sharing of non-PURPA power supply costs be continued through the current PCA year.
- Staff recommends that normal conditions be assumed for the purpose of the PCA forecast. This results in a 0.0000 forecast rate component to this year's PCA.
- Staff recommends an adjustment to levelize and redistribute base power supply costs that affect true-up amounts for March 2008. This adjustment reduces the true-up amount by approximately $15.0 million.
- Staff has included the $16.5 million SO2 allowance sales credit that the Company's initial filing did not include.
- Staff recommends that the Commission accept the administrative tariff changes proposed by the Company.
- Staff recommends that the Commission convene workshops to discuss various elements of the PCA.
- Finally, Staff recommends that the Commission accept the proposed PCA effective date of June 1, 2008.

Respectfully submitted this 20th day of May 2008.

Donald L. Howell, II
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Deputy Attorney General

Technical Staff: Kathy Stockton
Keith Hessing
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Terri Carlock

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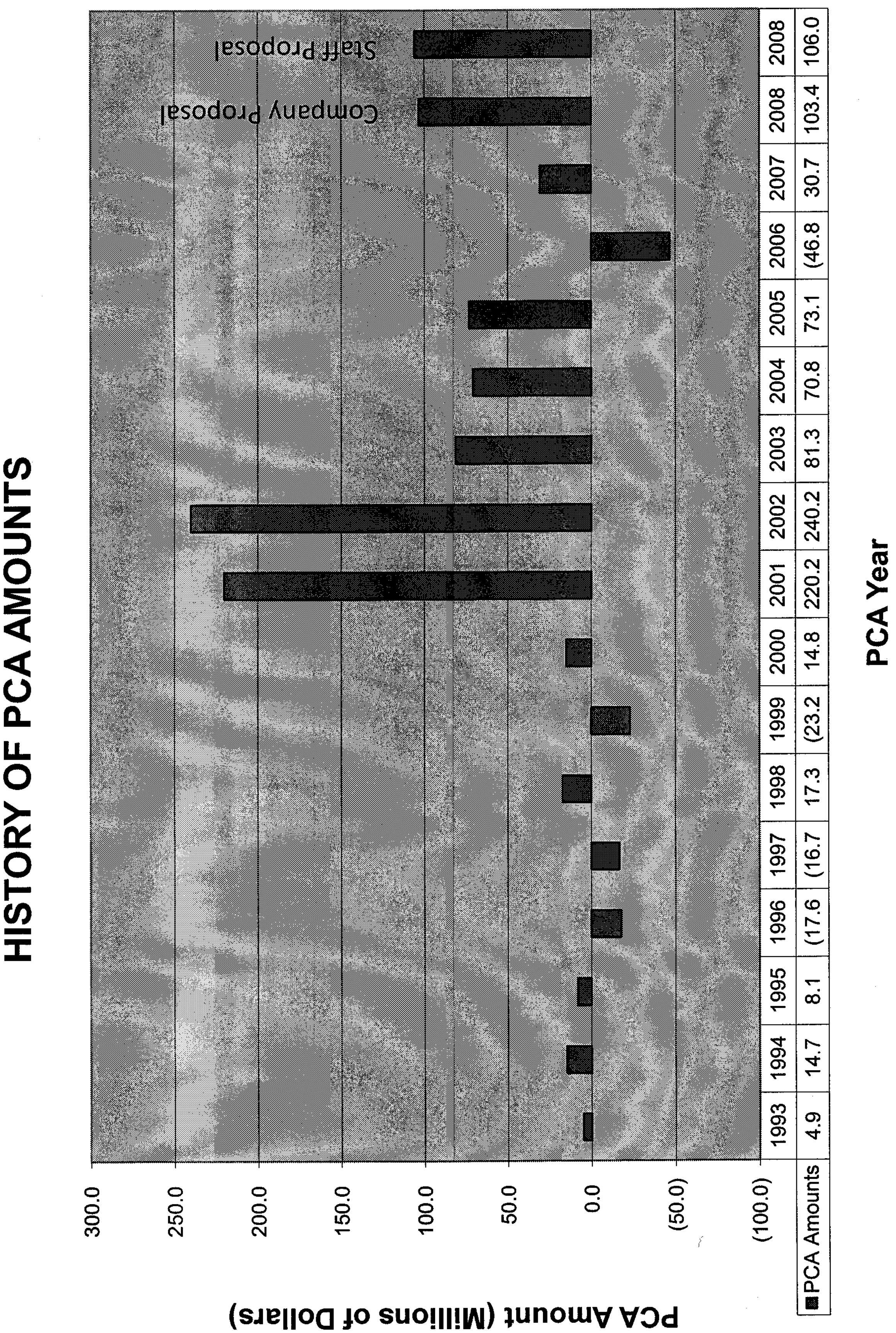
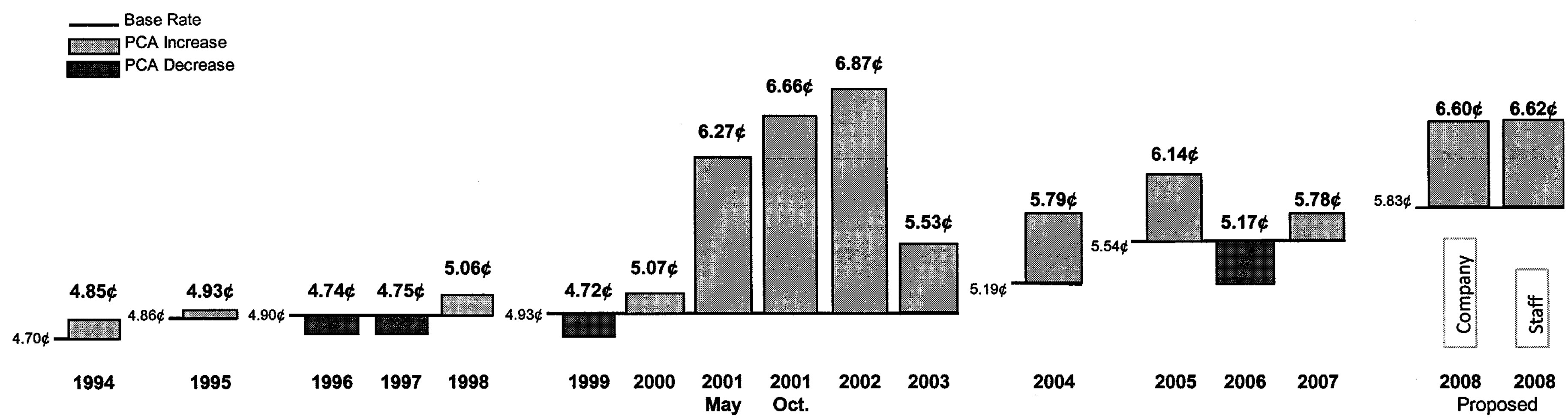


	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2008
■PCA Amounts	4.9	14.7	8.1	(17.6	(16.7	17.3	(23.2	14.8	220.2	240.2	81.3	70.8	73.1	(46.8	30.7	103.4	106.0

Attachment A
Case No. IPC-E-08-7
K. Hessing, Staff
5/20/08

AVERAGE RESIDENTIAL ENERGY RATES FOR IDAHO POWER COMPANY

Cents per Kilowatt-hour



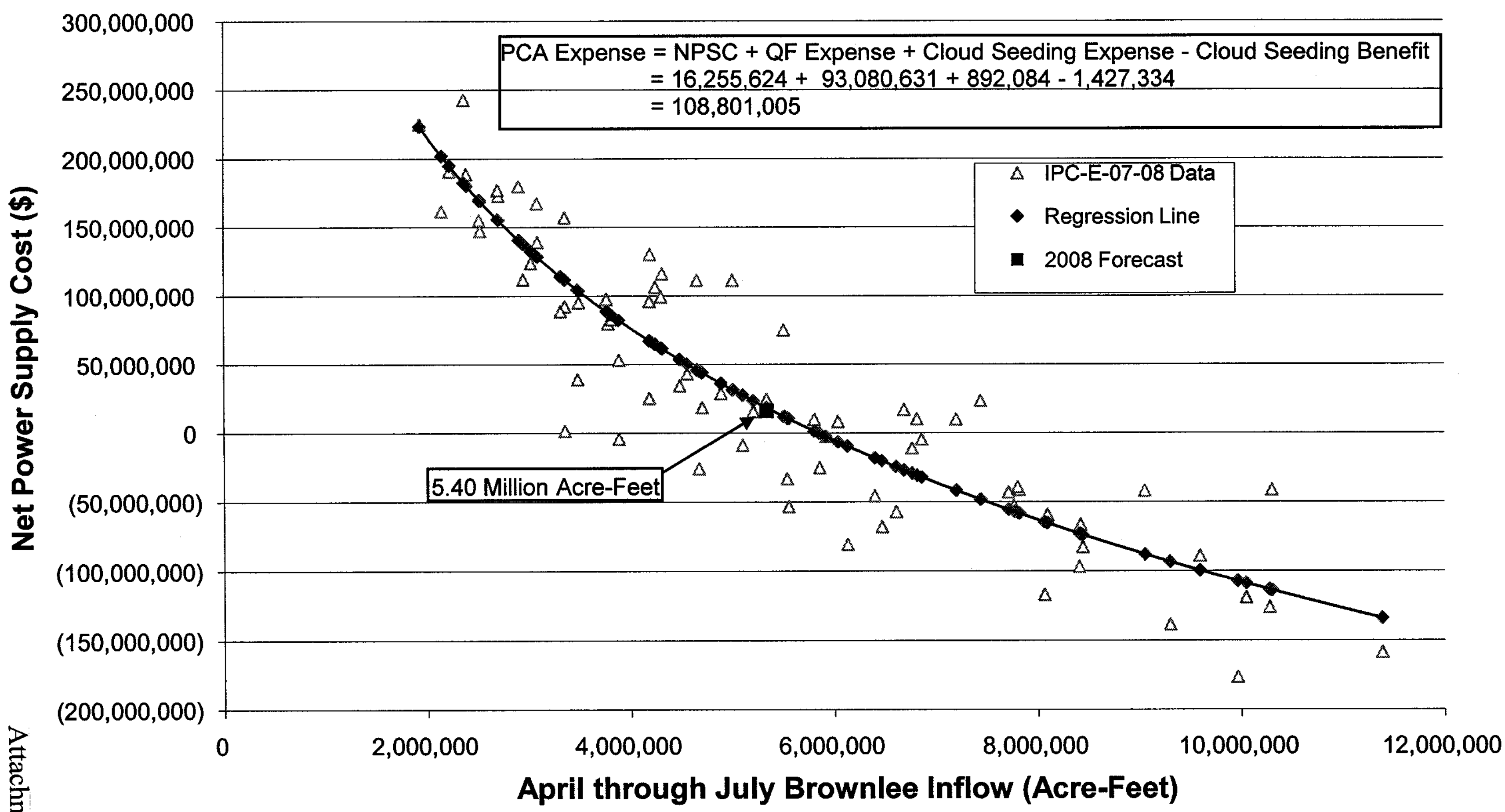
These rates do not include the monthly Service Charge, the BPA Credit, the Energy Efficiency Rider or any Local Franchise Fees that may apply.

Attachment B
Case No. IPC-E-08-7
K. Hessing, Staff
5/20/08

U:\khessin\IPCE0807\PCA History Chart 5/20/2008 KDH

IDAHO POWER'S 2008 PCA FORECAST

IPC-E-08-07 Sixteenth Annual PCA



Attachment C
Case No. IPC-E-08-7
K. Hessing, Staff
5/20/08

2008-2009 PCA - Sixteenth Annual
IPC-E-08-07
Staff Case - 90/10 Sharing - With SO2 Credit - Normal Power Supply Cost Forecast

(a) Line	(b) Description	(c) Units	(d) Base	(e) Forecast	(f) Difference	(g) Rate
1	**Projection 2008-2009:**					
2	PCA Expense	($)	127,510,052	108,801,005	(18,709,047)	
3	Normalized System Firm Sales	(MWH)	14,239,221	14,239,221		
4	Energy Rate	(¢/kWh)	0.89548	0.76409	-0.13139	
5	Sharing Percentage	(%)			100%	
6	Calculated Forecast Rate	(¢/kWh)			-0.131390945	(0.1314)
7	Normal Power Supply Cost Forecast	(¢/kWh)				**0.0000**
8						
9			($)	(MWh)	($/MWh)	(¢/kWh)
10						
11	**True-Up of 2007-2008:**		117,637,863	13,475,244	8.729924519	0.8730
12	2007 SO2 Credit (Order No. 30529)		(16,525,880)	13,475,244	-1.226388183	(0.1226)
13	Total		101,111,983			**0.7504**
14						
15	**True-Up of the True-Up:**		4,862,487	13,475,244	0.360845933	**0.0361**
16						
17	**PCA Rates:**					
18	PCA Rate Adjustment From Base	(¢/kWh)				$\boxed{0.7864}$
19	PCA Rate Currently in Effect	(¢/kWh)				0.2419
20	Difference - Last Year to This Year	(¢/kWh)				0.5445
21						
22	Note: Negative rates and amounts indicate benefits to ratepayers.					
23						
24						
25	**Expected PCA Revenues:**		Rate	Energy	Revenue	
26			($/MWh)	(MWh)	($)	
27						
28	Forecast Revenue		0.000	13,475,244	0	
29	True Up Revenue		7.504	13,475,244	101,111,493	
30	True Up of True Up Revenue		0.361	13,475,244	4,861,868	
31	Total		7.864		105,973,361	

Attachment D
Case No. IPC-E-08-7
K. Hessing, Staff
5/20/08

TRUE-UP CALCULATIONS FOR 2007 - 2008
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-08-07
Staff Case

1			2007	2007	2007	2007	2007	2007	2007
2	DESCRIPTION	Units	APR	MAY	JUN	JUL	AUG	SEPT	OCT
3	**PCA Revenue**								
4	Normalized Idaho Jurisd. Sales	MWh	897,400	954,886	1,074,252	1,273,977	1,295,480	1,168,367	996,812
5	Forecast Rate	m/KWh	-2.507	-2.507	1.888	1.888	1.888	1.888	1.888
6	Revenue	$	(2,249,782)	(2,393,899)	2,028,188	2,405,269	2,445,866	2,205,877	1,881,981
7									
8	**Load Change Adjustment**								
9	Actual System Firm Load - Adjusted	MWh	1,084,842	1,362,862	1,529,771	1,816,224	1,601,848	1,235,732	1,110,759
10	Normalized Firm Load	MWh	1,058,845	1,214,518	1,395,617	1,567,783	1,482,896	1,185,594	1,080,868
11	Load Change	MWh	25,997	148,344	134,154	248,441	118,952	50,138	29,891
12	Expense Adjustment (@16.84)	$	(764,572)	(4,362,797)	(3,945,469)	(7,306,650)	(3,498,378)	(1,474,559)	(879,094)
13									
14	**Non-QF PCA**								
15	ACTUAL:								
16	Water Lease Purchases	$	0	0	0	0	0	0	0
17	Cloud Seeding Program	$	38,151	134,410	14,404	20,821	36,610	35,614	32,816
18	Fuel Expense - Coal	$	7,054,816	6,864,119	9,993,704	10,070,154	10,923,868	10,044,287	10,335,306
19	Fuel Expense - Danskin	$	218,076	86,161	317,499	1,339,292	1,182,463	107,999	327,875
20	Fuel Expense - Bennett Mountain	$	476,410	1,030,447	1,546,947	3,628,106	3,913,614	1,507,932	330,946
21	Non-Firm Purchases	$	16,406,594	18,771,590	30,645,120	37,490,579	34,713,027	19,361,423	12,716,799
22	Telocaset Wind Power Partners	$							
23	Surplus Sales	$	(11,789,134)	(6,491,031)	(17,002,829)	(8,336,480)	(10,788,903)	(14,133,137)	(13,708,709)
24	Expense Adjustment (@16.84)	$	(764,572)	(4,362,797)	(3,945,469)	(7,306,650)	(3,498,378)	(1,474,559)	(879,094)
25	Sub-Total	$	11,640,341	16,032,898	21,569,376	36,905,822	36,482,302	15,449,559	9,155,939
26									
27	BASE:								
28	Fuel Expense - Coal	$	7,095,536	6,786,200	6,342,000	8,714,200	8,720,308	8,448,908	8,726,408
29	Fuel Expense - Danskin	$	264,800	276,900	275,700	279,600	280,800	264,700	272,300
30	Fuel Expense - Bennett Mountain	$	32,200	257,100	406,100	253,200	256,700	20,900	22,400
31	Non-Firm Purchases	$	26,700	586,700	2,715,400	3,166,600	2,765,200	479,300	35,800
32	Surplus Sales	$	(9,234,000)	(6,792,900)	(4,831,500)	(2,542,200)	(3,601,100)	(5,736,200)	(5,012,200)
33	Cloud Seeding Expense	$	0	0	0	0	0	0	167,423
34	Cloud Seeding Benefit	$	0	0	0	0	0	0	(316,667)
35	Sub-Total	$	(1,814,764)	1,114,000	4,907,700	9,871,400	8,421,908	3,477,608	3,895,464
36									
37	Change From Base	$	13,455,105	14,918,898	16,661,676	27,034,422	28,060,394	11,971,951	5,260,475
38	Emission Allowance Sales Credit	$	0	0	0	0	0	0	0
39	Sub-Total	$	13,455,105	14,918,898	16,661,676	27,034,422	28,060,394	11,971,951	5,260,475
40									
41	Deferral (Shared and Allocated)	$	11,395,129	12,634,815	14,110,774	22,895,452	23,764,347	10,139,045	4,455,096
42									
43	**QF Deferral**								
44	Actual (includes Net Metering)	$	3,113,321	4,334,632	6,206,673	6,508,807	6,037,646	4,729,092	3,069,894
45	Base	$	3,011,503	4,537,814	7,292,829	7,540,664	7,158,661	5,503,768	4,561,853
46									
47	Change From Base	$	101,818	(203,182)	(1,086,156)	(1,031,858)	(1,121,015)	(774,676)	(1,491,959)
48	Deferral (Allocated)	$	95,810	(191,194)	(1,022,073)	(970,978)	(1,054,875)	(728,971)	(1,403,934)
49									
50	**Total Deferral** (-6+41+48)	$	13,740,721	14,837,520	11,060,513	19,519,205	20,263,606	7,204,198	1,169,181
51									
52	**Principal Balances**								
53	Beginning Balance	$	0	13,740,721	28,578,241	39,638,754	59,157,959	79,421,565	86,625,763
54	Amount Deferred	$	13,740,721	14,837,520	11,060,513	19,519,205	20,263,606	7,204,198	1,169,181
55	Ending Balance	$	13,740,721	28,578,241	39,638,754	59,157,959	79,421,565	86,625,763	87,794,944
56									
57	**Interest Balances**								
58	Accrual thru Prior Month	$	0	(3)	57,252	176,323	340,150	586,641	917,576
59	Interest @ 5% per Year	$	0	57,253	119,076	165,161	246,491	330,923	360,941
60	Prior Month's Interest Adj.	$	(3)	2	(5)	(1,334)	(1)	12	(113)
61	Total Current Month Interest	$	(3)	57,255	119,071	163,827	246,490	330,935	360,827
62	Interest Accrued to Date	$	(3)	57,252	176,323	340,150	586,641	917,576	1,278,403
63	**Balance (True-Up & Interest)**	$	13,740,717	28,635,492	39,815,076	59,498,109	80,008,206	87,543,339	89,073,348
64									
65	**True-Up of the True-Up**								
66	True-Up Revenues (Collections)	$	(1,080,306)	(1,090,943)	(920,299)	1,081,301	782,018	692,205	538,019
67									
68	Beginning Balance	$	(7,941,094)	35,396,884	36,635,314	10,570,643	9,533,386	8,791,090	8,135,515
69	Adjustments:								
70	2006-07 PCA Transfer (ON 30047)	$	42,115,280	0	0	0	0	0	0
71	Tax Settlement True-Up (ON 30041)	$	0	0	(27,025,012)	0	0	0	0
72		$	0	0	0	0	0	0	0
73	Sub-Total	$	34,174,186	35,396,884	9,610,301	10,570,643	9,533,386	8,791,090	8,135,515
74	Interest @ 5% per Year	$	142,392	147,487	40,043	44,044	39,722	36,630	33,898
75	Revenue Applied to Interest	$	142,392	147,487	40,043	44,044	39,722	36,630	33,898
76	Revenue Applied to Balance	$	(1,222,698)	(1,238,430)	(960,341)	1,037,257	742,296	655,575	504,121
77	**True-Up of the True-Up Balance**	$	35,396,884	36,635,314	10,570,643	9,533,386	8,791,090	8,135,515	7,631,394
78									
79	Note: Negative amounts indicate benefit to ratepayers								

Attachment E
Case No. IPC-E-08-7
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TRUE-UP CALCULATIONS FOR 2007 - 2008
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-08-07
Staff Case

1			2007	2007	2008	2008	2008	
2	DESCRIPTION	Units	NOV	DEC	JAN	FEB	MAR	TOTALS
3	**PCA Revenue**							
4	Normalized Idaho Jurisd. Sales	MWh	912,336	1,021,056	1,096,401	1,032,663	1,030,393	12,754,023
5	Forecast Rate	m/KWh	1.888	1.888	1.888	1.888	1.888	
6	Revenue	$	1,722,490	1,927,754	2,070,005	1,949,668	1,945,382	15,938,798
7								
8	**Load Change Adjustment**							
9	Actual System Firm Load - Adjusted	MWh	1,171,433	1,367,764	1,409,978	1,211,697	1,166,380	16,069,290
10	Normalized Firm Load	MWh	1,122,464	1,274,108	1,265,091	1,092,645	1,141,512	14,881,941
11	Load Change	MWh	48,969	93,656	144,887	119,052	24,868	1,187,349
12	Expense Adjustment (@16.84)	$	(1,440,178)	(2,754,423)	(4,261,127)	(3,501,319)	(780,731)	(34,969,297)
13								
14	**Non-QF PCA**							
15	ACTUAL:							
16	Water Lease Purchases	$	0	0	0	0	0	0
17	Cloud Seeding Program	$	62,605	172,245	32,340	99,952	118,849	798,817
18	Fuel Expense - Coal	$	10,266,582	10,008,605	11,330,411	11,507,696	11,043,805	119,443,355
19	Fuel Expense - Danskin	$	65,829	72,176	287,686	28,086	411,179	4,444,320
20	Fuel Expense - Bennett Mountain	$	275,503	802,330	1,893,792	704,891	268,535	16,379,453
21	Non-Firm Purchases	$	15,620,132	10,927,735	15,938,927	7,080,919	13,812,727	233,485,572
	Telocaset Wind Power Partners	$	3,540	737,892	1,254,886	991,420	688,679	3,676,418
23	Surplus Sales	$	(8,439,918)	(891,111)	(10,334,789)	(5,317,445)	(15,924,244)	(123,157,730)
24	Expense Adjustment (@16.84)	$	(1,440,178)	(2,754,423)	(4,261,127)	(3,501,319)	(780,731)	(34,969,297)
25	Sub-Total	$	16,414,095	19,075,450	16,142,127	11,594,201	9,638,800	220,100,910
26								
27	BASE:							
28	Fuel Expense - Coal	$	8,442,408	8,726,608	8,453,508	7,372,808	5,895,851	93,724,743
29	Fuel Expense - Danskin	$	264,400	273,100	272,200	257,500	201,811	3,183,811
30	Fuel Expense - Bennett Mountain	$	6,100	99,700	51,100	26,300	91,967	1,523,767
31	Non-Firm Purchases	$	603,000	841,100	387,500	84,000	729,244	12,420,544
32	Surplus Sales	$	(1,419,600)	(3,443,800)	(5,889,800)	(7,776,100)	(3,994,247)	(60,273,647)
33	Cloud Seeding Expense	$	167,423	167,423	167,423	167,423	62,270	899,385
34	Cloud Seeding Benefit	$	(316,667)	(316,667)	(316,667)	(316,667)	(117,779)	(1,701,114)
35	Sub-Total	$	7,747,064	6,347,464	3,125,264	(184,736)	2,869,118	49,777,490
36								
37	Change From Base	$	8,667,031	12,727,986	13,016,863	11,778,937	6,769,682	170,323,420
38	Emission Allowance Sales Credit	$	0	0	0	0	0	0
39	Sub-Total		8,667,031	12,727,986	13,016,863	11,778,937	6,769,682	170,323,420
40								
41	Deferral (Shared and Allocated)	$	7,340,109	10,779,331	11,023,981	9,975,582	5,769,800	144,283,461
42								
43	**QF Deferral**							
44	Actual (includes Net Metering)	$	2,263,447	2,603,216	2,242,484	2,143,913	1,890,490	45,143,614
45	Base	$	3,239,593	3,483,863	3,036,410	2,957,595	7,756,719	60,081,272
46								
47	Change From Base	$	(976,146)	(880,647)	(793,926)	(813,682)	(5,866,230)	(14,937,659)
48	Deferral (Allocated)	$	(918,554)	(828,689)	(747,084)	(765,675)	(5,555,320)	(14,091,534)
49								
50	**Total Deferral** (-6+41+48)	$	4,699,065	8,022,889	8,206,892	7,260,239	(1,730,902)	114,253,128
51								
52	**Principal Balances**							
53	Beginning Balance	$	87,794,944	92,494,009	100,516,898	108,723,790	115,984,030	
54	Amount Deferred	$	4,699,065	8,022,889	8,206,892	7,260,239	(1,730,902)	114,253,128
55	Ending Balance	$	92,494,009	100,516,898	108,723,790	115,984,030	114,253,128	
56								
57	**Interest Balances**							
58	Accrual thru Prior Month	$	1,278,403	1,644,230	2,029,641	2,448,452	2,901,468	
59	Interest @ 5% per Year	$	365,812	385,392	418,820	453,016	483,267	3,386,153
60	Prior Month's Interest Adj.	$	14	20	(10)	(0)	0	(1,418)
61	Total Current Month Interest	$	365,827	385,412	418,811	453,015	483,267	3,384,734
62	Interest Accrued to Date	$	1,644,230	2,029,641	2,448,452	2,901,468	3,384,734	
63	**Balance (True-Up & Interest)**	$	94,138,239	102,546,539	111,172,243	118,885,497	117,637,863	**117,637,863**
64								
65	**True-Up of the True-Up**							
66	True-Up Revenues (Collections)	$	687,700	414,019	642,705	614,877	545,264	2,906,562
67								
68	Beginning Balance	$	7,631,394	6,975,491	6,590,537	5,975,292	5,385,312	(7,941,094)
69	Adjustments:							
70	2006-07 PCA Transfer (ON 30047)	$	0	0	0	0	0	42,115,280
71	Tax Settlement True-Up (ON 30041)	$	0	0	0	0	0	(27,025,012)
72	0	$	0	0	0	0	0	0
73	Sub-Total	$	7,631,394	6,975,491	6,590,537	5,975,292	5,385,312	7,149,173
74	Interest @ 5% per Year	$	31,797	29,065	27,461	24,897	22,439	
75	Revenue Applied to Interest	$	31,797	29,065	27,461	24,897	22,439	619,875
76	Revenue Applied to Balance	$	655,903	384,955	615,245	589,980	522,825	2,286,687
77	**True-Up of the True-Up Balance**	$	6,975,491	6,590,537	5,975,292	5,385,312	4,862,487	**4,862,487**
78								
79	Note: Negative amounts indicate benefit to ratepayers							

Attachment E
Case No. IPC-E-08-7
K. Hessing, Staff
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Distribution of PCA Amounts
IPC-E-08-07
Staff Case

Description	Initial Amount ($)	Allocated to Other Jurisdictions ($)	Shared with Shareholders ($)	Idaho Customer Revenue Requirement ($)	**PCA Rates (¢/kWh)**
Forecast (2008-2009)	0	0	0	0	**0.0000**
True Up (2007-2008)					
Revenue from Forecast Rate	(15,938,798)			(15,938,798)	
Non-QF Power Supply Cost Difference	205,292,717	12,066,968	19,322,575	173,903,174	
Load Growth Adjustment	(34,969,297)	(2,058,504)	(3,291,079)	(29,619,714)	
QF Power Supply Cost Difference	(14,937,659)	(846,125)	0	(14,091,534)	
Interest During Deferral Period	3,384,734			3,384,734	
Sub-Total	142,831,697	9,162,339	16,031,496	117,637,862	
Emission Allowance Credit (O.N. 30529)	(16,525,880)			(16,525,880)	
Sub-Total	126,305,817	9,162,339	16,031,496	101,111,982	**0.7504**
True Up of the True Up					
Amount Carried Forward	(7,941,094)			(7,941,094)	
Other Limited Term Adjustments:					
2006-2007 PCA Transfer (O.N. 30047)	42,115,280			42,115,280	
Tax Settlement True Up (O.N. 30041)	(27,025,012)			(27,025,012)	
Interest During Amortization	619,875			619,875	
Collections from True Up Rate	(2,906,562)			(2,906,562)	
Sub-Total	4,862,487	0	0	4,862,487	**0.0361**
Total Power Cost Adjustment (PCA)	131,168,304	9,162,339	16,031,496	105,974,469	**0.7864**

Attachment F
Case No. IPC-E-08-7
K. Hessing, Staff
5/20/08

ATTACHMENT G

IPC-E-08-07
Idaho Power Company
Summary of Revenue Impact
State of Idaho
Normalized 12-Months Ending December 31, 2007
STAFF CASE

Base Rates to 6/1/08 PCA (90/10 Sharing) (With SO2 Credit) (Forecasted Normal PS Costs)

Line No	Tariff Description	(1) Rate Sch. No.	(2) 2007 Avg. Number of Customers	(3) 2007 Sales Normalized (kWh)	(4) 03/01/08 Base Revenue	(5) 06/01/08 PCA Adjustment	(6) Total Revenue	(7) Average ¢/kWh	(8) Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1	386,118	4,961,656,042	307,761,279	39,018,463	346,779,742	6.989	12.68%
2	Residential Service Energy Watch	4	73	1,096,793	66,420	8,625	75,045	6.842	12.99%
3	Residential Service Time-of-Day	5	86	1,344,209	82,234	10,571	92,805	6.904	12.85%
4	Small General Service	7	31,133	208,043,392	16,250,923	1,636,053	17,886,976	8.598	10.07%
5	Large General Service	9	24,919	3,450,030,959	146,852,585	27,131,043	173,983,628	5.043	18.48%
6	Dusk to Dawn Lighting	15	-	5,902,712	983,720	46,419	1,030,139	17.452	4.72%
7	Large Power Service	19	116	2,145,340,040	69,593,761	16,870,954	86,464,715	4.030	24.24%
8	Agricultural Irrigation Service	24	15,375	1,539,304,092	74,751,104	12,105,087	86,856,191	5.643	16.19%
9	Unmetered General Service	39	0	0	0	0	0	0.000	0.00%
10	Unmetered General Service	40	1,701	16,337,412	930,280	128,477	1,058,757	6.481	13.81%
11	Street Lighting	41	125	20,675,782	2,172,237	162,594	2,334,831	11.293	7.49%
12	Traffic Control Lighting	42	131	5,474,735	199,193	43,053	242,246	4.425	21.61%
13	*Total Uniform Tariffs*		459,777	12,355,206,168	619,643,736	97,161,339	716,805,075	5.802	15.68%
	Special Contracts:								
14	Micron	26	1	702,140,245	19,691,563	5,521,631	25,213,194	3.591	28.04%
15	J R Simplot	29	1	188,325,624	4,921,209	1,480,993	6,402,202	3.400	30.09%
16	DOE	30	1	215,500,001	5,689,217	1,694,692	7,383,909	3.426	29.79%
17	*Total Special Contracts*		3	1,105,965,870	30,301,989	8,697,316	38,999,305	3.526	28.70%
18	***Total Idaho Retail Sales***		459,780	13,461,172,038	649,945,725	105,858,655	755,804,380	5.615	16.29%

Attachment G
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K. Hessing, Staff
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IPC-E-08-07
Idaho Power Company
Summary of Revenue Impact
State of Idaho
Normalized 12-Months Ending December 31, 2007
STAFF CASE

6/1/07 PCA to 6/1/08 PCA (90/10 Sharing) (With SO2 Credit) (Forecasted Normal PS Costs)

Line No	Tariff Description	(1) Rate Sch. No.	(2) 2007 Avg. Number of Customers	(3) 2007 Sales Normalized (kWh)	(4) 03/01/08 Base & PCA Revenue	(5) 06/01/08 PCA Adjustment	(6) Total Revenue	(7) Average ¢/kWh	(8) Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1	386,118	4,961,656,042	319,763,525	27,016,217	346,779,742	6.989	8.45%
2	Residential Service Energy Watch	4	73	1,096,793	69,073	5,972	75,045	6.842	8.65%
3	Residential Service Time-of-Day	5	86	1,344,209	85,486	7,319	92,805	6.904	8.56%
4	Small General Service	7	31,133	208,043,392	16,754,180	1,132,796	17,886,976	8.598	6.76%
5	Large General Service	9	24,919	3,450,030,959	155,198,210	18,785,419	173,983,629	5.043	12.10%
6	Dusk to Dawn Lighting	15	-	5,902,712	997,999	32,140	1,030,139	17.452	3.22%
7	Large Power Service	19	116	2,145,340,040	74,783,339	11,681,377	86,464,716	4.030	15.62%
8	Agricultural Irrigation Service	24	15,375	1,539,304,092	78,474,681	8,381,511	86,856,192	5.643	10.68%
9	Unmetered General Service	39	0	0	0	0	0	0.000	0.00%
10	Unmetered General Service	40	1,701	16,337,412	969,800	88,957	1,058,757	6.481	9.17%
11	Street Lighting	41	125	20,675,782	2,222,252	112,580	2,334,832	11.293	5.07%
12	Traffic Control Lighting	42	131	5,474,735	212,436	29,810	242,246	4.425	14.03%
13	*Total Uniform Tariffs*		459,777	12,355,206,168	649,530,981	67,274,098	716,805,079	5.802	10.36%
	Special Contracts:								
14	Micron	26	1	702,140,245	21,390,040	3,823,154	25,213,194	3.591	17.87%
15	J R Simplot	29	1	188,325,624	5,376,769	1,025,433	6,402,202	3.400	19.07%
16	DOE	30	1	215,500,001	6,210,512	1,173,398	7,383,910	3.426	18.89%
17	*Total Special Contracts*		3	1,105,965,870	32,977,321	6,021,985	38,999,306	3.526	18.26%
18	***Total Idaho Retail Sales***		459,780	13,461,172,038	682,508,302	73,296,083	755,804,385	5.615	10.74%

Attachment H
Case No. IPC-E-08-7
K. Hessing, Staff
5/20/08

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 20TH DAY OF MAY 2008, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-08-7, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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