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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, 2011 THROUGH MAY 31, 2012.	**CASE NO. IPC-E-11-06** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of Record, Donald L. Howell II, Deputy Attorney General, and submits the following comments in response to Order No. 32227 issued on April 21, 2011.

BACKGROUND

Idaho Power Company filed its annual power cost adjustment (PCA) Application on April 15, 2011 for rates to become effective June 1, 2011 through May 31, 2012. The PCA is a symmetrical rate adjustment mechanism that annually adjusts rates to recover a portion of above normal power supply costs from customers, or refund a portion of below normal power supply costs to customers. Idaho Power calculates the total PCA revenue reduction to be approximately $40.4 million which would result in an average rate decrease of approximately 4.78%. The total PCA rate (Schedule No. 55) is combined with the Company's other base rates to determine a customer's overall billing rate.

IDAHO POWER COMPANY'S FILING

The Power Cost Adjustment (PCA) Mechanism

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

1. The Forecast. Forecasted power supply costs for the coming year are based on the Company's most recent Operating Plan. The difference between forecasted and actual power supply cost is calculated. The power supply cost difference is converted to a cents per kilowatt-hour (¢/kWh) rate by dividing the power costs by energy sales. In this filing the Company calculates above normal power supply costs of $4.6 million relative to power supply costs contained in current base rates. After the PCA 95/5 sharing, this produces rates to recover projected above normal power supply costs of 0.0445 ¢/kWh.

2. The True-up. The true-up amount is the difference between normal and actual power supply costs during the previous year. The amount is offset with revenue from the forecast rate. The previous year's PCA amount is not precisely recovered due to actual power supply costs being different than forecasted power supply costs. The true-up amount is converted to a ¢/kWh rate by reducing the deferral balance by the $S0_2$ credit, and dividing by projected energy sales. Idaho Power calculates the true-up amount and surcharge rate to be $3,689,374 and 0.0273 ¢/kWh, respectively.

3. The Reconciliation. The reconciliation of the true-up tracks the recovery of the previous year's true-up amounts. It nets the actual revenue collected from the true-up rates against the amounts set for recovery. Any difference is carried into the following year's true-up reconciliation along with the true-up difference. Idaho Power calculates the reconciliation of the true-up amount and rate to be a credit of $18,152,666 and 0.1347 ¢/kWh, respectively.

In summary, the total PCA rate for each class will be the combination of the three PCA rate components discussed above, and an Energy Efficiency Rider Recovery rate. The combination of the three traditional PCA components produces a 2011/2012 PCA rate credit (discussed below) of 0.0629 ¢/kWh (0.0445 + 0.0273 -0.1347). The Energy Efficiency Rider rate component is not spread on an equal ¢/kWh basis and is different for each class (see Company Exhibit No. 2).

Energy Efficiency Rider Recovery

In Case No. IPC-E-10-27, the Commission authorized recovery of $10 million in the PCA for DSM expenditures previously deemed prudent through 2009 and currently deferred in the Energy Efficiency Tariff Rider account (Order No. 32217). When allocating the DSM expenditures in the PCA, the Commission ordered the Company "to separate the DSM expenditures and allocate them to each customer class based on the amount that would have been recovered from each class through the Rider." Order No. 32217 at 6. Idaho Power allocated $10 million among the customer classes based on forecasted base revenue for the PCA year (June 1, 2011 through May 31, 2012). The component surcharge rate for tariff customers ranges from a low of 0.0391 ¢/kWh to a high of 0.2084 ¢/kWh (Company Exhibit No. 2).

STAFF AUDIT AND ANALYSIS

A. The PCA Forecast or Projection

The Operating Plan used to forecast power supply costs is based on the Company's most current information available. It takes several factors into consideration such as water conditions, gas hedges, market purchases, transmission availability, and the SO_2 and Renewable Energy Credit markets. Throughout the year a Risk Management Committee (RMC) comprised of key employees reviews the Company's risk management policy. An account by account breakdown of the Company's power supply expense forecast is shown on Attachment A to these comments. The chart shows expenses included in Base Rates, Forecasted Expenses and the Difference. Account 555 – PURPA Purchase Expense is shown separately from other Account 555 Non-PURPA Expenses because differences in PURPA Expenses are not shared and the entire difference is passed on to customers.

Attachment B shows Staff's calculation of the PCA rate. Line 1 through 15 shows the calculation of the Forecast Rate. Line 3, Column (e), shows the forecast offset due to expected Hoku first block revenues. Line 4, Column (e), shows an expected reduction in power supply costs associated with the sale of Renewable Energy Credits (REC) and SO_2 Emission Allowances. Line 6, Column (f), shows the 95% sharing percentage that is applied to all power supply cost differences, except PURPA costs. Line 9, Column (g), shows the forecast rate excluding the portion of the forecast rate associated with the expected PURPA cost difference. This forecast component rate is negative 0.2167 ¢/kWh. Lines 11 through 13 show the calculation of the portion of the Forecast Rate associated with the expected difference in PURPA costs. This component rate is 0.2612 ¢/kWh. These two components combine to produce the power supply forecast rate of 0.0445¢/kWh shown on line 15. Among other things, this rate reflects water conditions that are expected to be well above normal. While Idaho Power conducts its own water forecast, the Northwest River Forecast Center confirms that the April through July Brownlee Reservoir inflow is expected to be 144% of normal. Although this year's forecasted rate is proposed to be substantially lower than last year's forecasted rate, power supply costs are still projected to be approximately $4.6 million above normal. This is primarily because the Company expects its PURPA Expenses to be $36.9 million above the PURPA Expenses included in base rates ($62.8 million).

B. Irrigation Peak Rewards Program

The Irrigation Peak Rewards Program is a voluntary load control program available to irrigation customers. It is used to decrease the Company's system summer peak load by turning off participating irrigation pumps during the period of June 15 through August 15 for a few hours at a time. This demand response program is dispatchable, reliable, and less expensive than heavy load hour market purchases.

The Staff monitors the Company's use of the Program because it directly impacts annual power supply costs, and ultimately the PCA rates paid by customers. When the Company purchases power during heavy load hours instead of interrupting as allowed by the Program, power supply expenses are higher than they otherwise would be. One of Staff's objectives is that the "operational potential of the [Peak Rewards] Program be fully utilized." Case No. IPC-E-10-46, Staff Comments, p. 3. During the 2010 Program season, participants were interrupted for 12 hours out of 60 potential hours, or 20% of potential hours. Consequently, Staff encourages the Company to lower its power supply costs by using more curtailment hours in the Irrigation Peak Rewards Program.

C. The PCA True-Up

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

Page 1, lines 4 through 78 of Company Exhibit No. 1 calculates the true-up deferral amount of $4,181,114. Attachment C to these comments is Staff's verification of the Company's true-up deferral calculations. In Order No. 30715 (Case No. IPC-E-08-19), the Commission authorized

Idaho Power to redistribute monthly base power supply costs in a specific manner to meet financial reporting needs of the Company. The monthly redistribution was to leave annual base power supply costs unchanged, which it has. Company Exhibit No. 1, page 3, shows the deferral calculation using base power supply costs before redistribution. The difference between the deferral balance shown on page 1 of Exhibit No. 1, and the balance shown on page 3 of Exhibit No. 1 is due to the base power supply costs being updated beginning June 2010 (Order No. 31042) (Case No. IPC-E-10-01). Had the base components been in place for the whole PCA year the two deferral balances would be equal. Thus, Staff finds the Company's calculation as shown on page 1 of Exhibit No. 1 to be correct.

To verify revenues and costs associated with Idaho Power's true-up deferrals, Staff conducted an audit of actual revenues and expenses that occurred during the PCA year. These revenues and costs included water lease expenses, fuel expenses for coal, fuel expenses for natural gas, power sales and purchases, third-party transmission expenses, Hoku First Block Energy revenues, green tag Sales Credit/RECs, and Qualifying Facilities expenses. Staff also examined the sale of SO_2 Allowances passed onto customers. The Risk Management Operating Plans and RMC minutes were also reviewed.

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

1. Load Change Adjustment. This year's true-up calculation includes a negative Load Change Adjustment[1] of $19,469,566. Actual loads during the true-up year were below normal loads in 10 of 12 months. The total below normal load was 731,114 MWh. This represents a 4.7% load decline. The load change adjustment is the product of the negative load growth and the load change adjustment rate (LCAR) of $26.63/MWh. The LCAR is composed of the variable and fixed costs of production embedded in base rates. When load grows the adjustment reduces power supply costs to avoid double counting production costs. When load declines the adjustment reimburses the Company for a portion of lost fixed production costs and makes the Company whole with respect to variable production costs except for the PCA sharing amounts. The result is that $19,469,566 million (before Jurisdictional Allocation and PCA sharing) has been added to the deferral balance for recovery from customers in this year's PCA. Staff notes that the Commission modified the LCAR calculation in Order No. 32206 and its impact will be considerably less in future PCAs. The Staff reviewed the new LCAR proposed by the Company. The calculations

[1] The Load Change Adjustment was formerly known as the "Load Growth Adjustment" and was intended to eliminate recovery of load deviations due to weather, customer growth, or changing customer usage patterns. Larkin Direct 12-13.

were revised in the response to a Staff Audit Request. The Staff recommends approval of the revised LCAR of 19.67 $/MWh.

2. Water Leases. The Company leases water for the production of power from several entities. The increase or decrease in the water lease expense from base rates is included in the PCA for recovery from or credit to customers. This year's PCA deferral balance includes actual water lease expenses of $2,055,185 and the amount included in base rates is $1,587,623, with the difference of $467,562 included in the deferral balance. This increase in water lease expenses from base expenses is a cost to customers and is subject to jurisdictional allocation and sharing.

3. Fuel Expense - Coal. A large portion of Idaho Power's electricity comes 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 credit to customers. For the audit period of April 2010 to March 2011, the total coal expense for the three plants is $138,868,030. The total coal expense included in base rates is $163,327,463. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $24,459,433. Thus, this reduction in coal costs from base costs is a credit to customers and is subject to jurisdictional allocation and sharing.

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

For the audit period of April 2010 to March 2011, the total variable gas and gas transportation expense for all the gas plants was $12,921,516. The total gas and gas transportation expense included in base rates is $6,084,896. This increase in gas expense from base rates is included in the PCA. In this year's PCA deferral balance, the additional gas expense that is included for future recovery from customers is $6,836,620 and is subject to jurisdictional allocation and sharing.

5. Power Sales and Purchases. Staff reviewed the power purchases and sales in conjunction with the Company's Operating Plan. Staff 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, 2011, the Company sold off-system surplus power totaling $70,077,566. The total surplus sales included in base rates is $96,181,927. This decrease in the power sales from base rates is included in the PCA. Actual surplus sales were less than base amounts by $26,104,361. This reduction of revenues is a cost to customers and is subject to jurisdictional allocation and sharing.

b. Power Purchases. During the PCA year ending March 31, 2011, the Company made market power purchases, excluding its PURPA contracts. The total amount of power purchases is $77,085,070. The amount of power purchases included in base rates is $65,523,728. Actual purchased power amounts exceed base amounts by $11,561,342. This difference is a cost to customers and is subject to jurisdictional allocation and sharing.

6. Third-Party Transmission. In Order No. 30715 (Case No. IPC-E-08-19), the Commission found that third-party transmission costs that are incurred in conjunction with market purchases and off-system sales should be tracked through the PCA like other variable power supply costs. Including transmission expenses in the PCA is a straightforward treatment of power supply costs that fluctuate with power purchases and sales.

For the audit period of April 2010 to March 2011, the actual third-party transmission expense is $5,812,011. The third-party transmission expense included in base rates is $8,587,977. Thus, this year's PCA deferral balance includes the difference between actual costs and base rate costs of $2,775,966. Because the actual costs are less than the amount included in base rates, this amount represents a benefit to customers. This benefit to customers is subject to jurisdictional allocation and sharing.

7. Hoku[2] First Block Energy. In Order No. 31042 (Case No. IPC-E-10-01), the Commission re-established the level of power supply costs included in base rates beginning June 1, 2010. In that Order, the Commission accepted the Staff's recommendation that Hoku loads and First Block revenues be excluded from net power supply costs included in base rates. This treatment causes all Hoku actual power supply costs and offsetting First Block Revenues to be captured in the PCA true-up deferral calculation. The deferred First Block Revenue of $26,961 shown on line 22 of Attachment C is a benefit to customers and is subject to jurisdictional allocation and sharing.

8. Renewable Energy Credit Sales. In Order No. 30818 (Case No. IPC-E-08-24), the Commission ordered that revenues from the sale of renewable energy credits (RECs or green tags)

[2] Hoku Materials is a special contract customer with a polysilicon production facility in Pocatello.

benefit customers, subject to jurisdictional allocations and sharing. The amount included in the deferral balance is $5,649,119 and is a benefit to customers.

9. Actual PURPA 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. Par 292), and has obtained certification of its QF status. There are two types of QFs - cogeneration facilities and small power production facilities.

For the audit period of April 2010 through March 2011, the actual PURPA expense is $64,792,474. The PURPA expense included in base rates is $63,051,665. The difference in the PURPA expense from base rates is included in the PCA for recovery from or credit to customers. In this year's PCA deferral balance, the actual PURPA expense was more than the PURPA expense included in base rates by $1,740,809. This amount is a cost to customers and increases the PCA deferral balance. PURPA contracts are not currently subject to sharing, but they are subject to jurisdictional allocation.

10. SO_2 Credits. In Order No. 32162 (Case No. IPC-E-10-20), the Commission ordered that $490,498 in jurisdictional SO_2 funds be used to offset the Company's PCA deferral balance in this PCA year. SO_2 Credits are subject to jurisdictional allocations and sharing. After including interest, the SO_2 revenues included in the deferral balance this year are $491,740.

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

Load Change Adjustment	$19,469,566
Water Leases	$467,562
Fuel Expense – Coal	$(24,459,433)
Fuel Expense – Gas	$6,836,620
Surplus Sales	$26,104,361
Non-Firm Purchases	$11,561,342
Third Party Transmission	$(2,775,966)
Hoku Energy	$(26,961)
Subtotal – Change from Base	$37,177,090
Renewable Energy Credit Sales	$(5,649,119)
Subtotal – Subject to Jurisdictional Allocations & Sharing	$31,527,971
Subtotal - After Jurisdictional Allocations and Sharing	$28,447,098
Qualifying Facilities – After Jurisdictional Allocations	$1,655,493
Total all Expense Items	$30,102,591
Less Jurisdictional Forecast Revenue	$25,952,179
Deferral Balance	**$4,150,412**
Interest on the Deferral Balance	$30,702
Sale of SO_2 Credits	$(491,740)
Deferral Balance (True-Up)	**$3,689,374**

The Company-proposed true-up rate surcharge is 0.0273 ¢/kWh. The Staff calculates the same rate as shown on Staff Attachment B, line 22.

D. The Reconciliation of the True-Up

The reconciliation of the true-up[3] amount is the difference between what was approved to be collected or refunded when the PCA rate for last year's true-up was set and what was actually collected or refunded. The reconciliation of the true-up 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.

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

Last year's reconciliation of the true-up included \$12.0 million from the forecast true-up and \$11.3 million that was under recovered in the reconciliation of the true-up. The two true-up rates in place last year to recover these amounts actually recovered \$41.2 million including interest at \$0.3 million. The amounts set for recovery were over recovered by \$18.2 million (12.0 + 11.3 – 41.2 – 0.3). This is the amount recommended for refund by the Company and Staff. When divided by expected sales it produces the reconciliation of the true-up rate credit of negative 0.1347 ¢/kWh.

E. 2010 Idaho Jurisdictional Return on Equity

In Order No. 30978, the Commission approved a Stipulation between the Company, Staff, and other parties in Case No. IPC-E-09-30. In the Stipulation, it was agreed that if the Company's actual return on year-end equity for the Idaho jurisdiction during 2009, 2010 or 2011 exceeded 10.5 %, then the amounts in excess of a 10.5% return would be shared equally between the Company's Idaho customers and the Company. Order No. 30978 at 2. If the return on equity fell below 9.5% percent, the Stipulation allows the Company to accelerate amortization of accumulated deferred investment tax credits.

In this PCA case, the Company calculated that the jurisdictional return on equity (ROE) was 10.37%, thus the sharing mechanism of the Stipulation was not triggered. Larkin Dir. at 15. However, the Staff proposes an adjustment to the Company's ROE calculation.

1. <u>Background</u>. A brief review of several cases is helpful in explaining Staff's adjustment to the ROE calculation. In October 2009, Idaho Power filed its 09-29 Application "seeking authority to implement a tracking mechanism to recover its defined benefit pension expense." Application at 2, Case No. IPC-E-10-08. The 09-29 Application noted that the Company's actuary informed the Company that a contribution to the Company's pension was required for the tax year beginning January 1, 2009 in the amount of \$5,418,622 if paid by October 15, 2009. If not paid by October 15, 2009, then interest on that amount shall accrue until the extended due date for Idaho Power's federal income tax return of September 15, 2010. The Company did not make an October 15, 2009 contribution. Order No. 31003 at 2.

The Commission declined to implement a tracking mechanism and instead allowed the Company to establish a "regulatory asset balancing account" for the purpose of tracking the difference between cumulative cash contributions to the pension plan and the amounts recovered in rates. *Id.* at 10. The Commission also noted that the contribution to the balancing account "in excess of the ERISA minimum...will not be disallowed solely because they are made sooner than they are legally required to be paid...." *Id.*

In March 2010, the Company filed another Application (Case No. IPC-E-10-08) seeking approval to contribute $5,416,796 to its pension plan on September 15, 2010. Order No. 31055 at 1. In addition, the Company proposed to recover this 2010 contribution by increasing customer rates by .77% for each customer class. *Id.* In final Order No. 31091, the Commission approved the proposed rate increase and the contribution to fund the pension plan in the amount of $5,416,796 as of September 15, 2010. Order No. 31091 at 3.

On March 15, 2011, Idaho Power filed Case No. IPC-E-11-04 seeking authority to increase rates to recover in part a $60 million contribution the Company made to its pension plan in September 2010. Although the Company's actuary had previously determined that the 2010 minimum contribution required by ERISA was approximately $5.8 million, the Company decided that it was appropriate to make a $60 million contribution instead. Application at 3. As stated in the Company's Application, if it had only contributed the minimum amount, its funding level at December 31, 2010 "would have been below 80%." *Id.* at 3-4. The Company claims that this would have "triggered certain plan restrictions, notice requirements to participants, and limitations on future funding alternatives." *Id* at 4. After reviewing several alternatives, the Company determined that making the $60 million contribution would: (1) maintain an 80% funding level; (2) reduce the premiums owed to the Pension Benefit Guarantee Corporation (PBGC); and (3) "approximate the required minimum funding through 2011." *Id.* The Company noted that the $60 million contribution would save the Company approximately $11 million over a 10-year period and save approximately $1 million in PBGC premium through 2012. *Id.* at 4. However, even with the $60 million contribution, the Company disclosed that its actuary determined that the Company will still be required to make a minimum contribution of $3 million by October 15, 2011, and an additional contribution of $5.7 million by January 15, 2012. *Id.*

2. The Staff's ROE Adjustment. In this PCA filing, the Company included a calculation of the Idaho Jurisdictional Return on Equity (ROE) for 2010 of 10.37%. Commission Staff verified the components in the calculation performed by the Company. Staff notes that the earnings on common stock and the common equity at year end used in the calculation agree with the amounts reported in the Company's 2010 10-K report to the Securities and Exchange Commission and Annual Report to Stockholders.

Comments by all parties (including Staff) in Case No. IPC-E-11-04 recommend accepting the $60 million pension contribution. However, for this PCA case, Staff believes the Company had more flexibility in timing when and how much of the $60 million contribution it made during 2010. This flexibility is important when discussing the ROE earnings test in this case pursuant to the Settlement Stipulation approved in Order No. 30978 (Case No. IPC-E-09-30).

In Order No. 31081 the Commission approved the Company's request to make a minimum $5.8 million contribution in September 2010. However, Staff believes the remainder of the $60 million payment ($54.2 million) might have been paid in the first quarter of 2011 and still avoid the negative effects mentioned above. Rather than reflect the $54.2 million as a 2011 obligation, Staff proposes, for the ROE test only, to amortize the $60 million payment over two years, for the years ended 2010 and 2011.

Staff notes that, had the Company only made the required ERISA payment, net income would have been $33 million more than the net income reported by the Company in the 2010 Annual Report. The lower level of pension funding would have resulted in a ROE that would have triggered sharing. Staff acknowledges that the Company was allowed to make contributions to its balancing account at the level it chose.[4] However, Staff cannot overlook the additional Company benefit the decision to fund the pension at the $60 million level in 2010 has on the coincidental action of not triggering any sharing with ratepayers.

Staff believes it is the responsibility of the Commission to assure that ratepayers are treated fairly with respect to the revenue sharing provisions of the Stipulation approved by Order No. 30978. Moreover, the ROE sharing mechanism was not evaluated in the recent pension review case (Case No. IPC-E-11-04). Consequently, Staff maintains that the interests of the Company and its customers can be reasonably balanced by amortizing the $60 million pension contribution over two years for the earnings test and recommends that the resulting 2010 revenue above a 10.5% ROE be shared with customers.[5]

Staff's proposed adjustment to amortize the pension contribution of $60 million over two years still recognizes the Company's entire pension contribution. This amortization, net of non-utility amounts, increases 2010 system net income by $17,714,189. The increase in net income

[4] "There may be circumstances where the Company could choose to contribute in excess of the minimum amount required by ERISA or prior to the final due date of the minimum payment...." Order No. 31003 at 9.

[5] Staff is aware that the amortization of this pension expense will also impact the ROE earnings test and potential sharing for next year's PCA filing. If this adjustment is accepted by the Commission, Staff fully expects the Company to include the remaining $30 million of pension expense in next year's ROE earnings test calculation.

changes the Idaho ROE from 10.37% to 11.65%. The increase in the return on equity triggers the sharing mechanism. The 50% sharing amount above 10.5% for Idaho ratepayers from this adjustment is $7,462,104.

Staff recommends the sharing amount of $7,462,104 be utilized to reduce the rate increase associated with DSM expense recovery in the PCA. As noted above, the Commission approved recovery of $10 million in DSM expenses incurred through 2009 in the 2011/2012 PCA, effective June 1, 2011. The sharing offset Staff proposes in this case reduces the DSM adjustment included in the PCA on June 1, 2011 to $2,537,896 ($10,000,000 - $7,462,104).

Staff believes reducing the DSM adjustment is reasonable for the following reasons. First, it simply reduces a previously approved DSM adder rather than affecting other base rates. Second, changing the DSM component properly allocates the sharing revenue to each customer class on a class revenue basis consistent with current base rate allocations.

Energy Efficiency Rider Recovery

Staff reviewed Idaho Power's class allocation of the Energy Efficiency Rider to make sure the methodology comports with the Commission's Order "to separate the DSM expenditures and allocate them to each customer class based on the amount that would have been recovered from each class through the Rider." Order No. 32217. As previously discussed, the Company based the $10 million allocation on forecasted base revenue during the coming PCA year (June 1, 2011 through May 31, 2012). Staff compared the Company's base revenue forecast for each class to actual base revenue in 2010 to evaluate the potential differences of how the $10 million surcharge might be allocated. The Company used a forecast of 2011/2012 customer revenues to allocate the DSM Expenses to the individual classes. Staff believes the forecast is reasonable and comparable to actual 2010 class revenues. Revenue sharing proceeds are allocated to the various customer classes on the same forecasted revenue basis to reduce DSM Expense recovery through the PCA. At the end of the year, any under- or over- collection of the net $2.5 million (10.0 million EER -7.5 million revenue sharing) in DSM Expenses will be included in the Energy Efficiency Rider deferral balance.

PCA RATES

The uniform PCA rate credit of 0.0629 ¢/kWh is the sum of the three components described above (0.0445 + 0.0273 -0.1347). This new PCA rate, shown on Attachment B, line 27 represents a PCA credit rather than the 0.3114 ¢/kWh surcharge currently in place. The new PCA rate constitutes a refund of the combined power cost components. In this case, the uniform PCA rate is combined with the Energy Efficiency Rider rate, net of the revenue sharing amount, to arrive at the total PCA rate for each class. Attachment D shows these rates.

Combined PCA and Energy Efficiency Rider Recovery

Attachment E shows the total PCA rate decrease for all Idaho Power customer classes. It includes the uniform PCA decrease and the Energy Efficiency Rider increase net of the Staff's ROE sharing adjustment amount. The impact is measured against all billed revenue. The total Staff-recommended decrease is $48.0 million (as compared to the Company's $40.4 million), representing an average decrease of 5.66%. The Schedule 1, Residential Class decrease is 4.44%, and the Schedule 19, Large Industrial class decrease is 8.39%, a reduction of 7.45 million.

Other PCA Attachments

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

CUSTOMER RELATIONS

Customer Notice and Press Release

Idaho Power's PCA Application contained both the customer notice and press release. Staff reviewed both and determined that they complied with requirements of Procedural Rule 125, IDAPA 31.01.01.125 (effective April 7, 2011). The customer notice was mailed with Idaho Power's cyclical billings beginning April 27, 2011 and ending May 25, 2011. Customers had until May 17, 2011 to file comments. Because this Application constitutes a rate decrease, Staff does not object to the fact that the comment period ends before all customers will have received the notice in their monthly bills.

Customer Comments

By May 11, 2011, one customer had sent a comment to the Commission regarding the PCA. That customer did not state whether or not he supported the decrease in rates. His comments focused on the long-term strategy for energy supplies.

STAFF RECOMMENDATION

Staff recommends that the Commission approve the PCA rate credit filed by the Company as modified by the Staff-proposed ROE adjustment to the DSM expense.

Staff recommends that the Commission approve a total PCA rate comprised of the uniform PCA decrease of 0.0629 ¢/kWh and class-specific rates, as shown on Attachment D, to recover the Energy Efficiency Rider surcharge net of Staff-proposed revenue sharing. The Staff recommends that the rate changes be effective June 1, 2011 through May 31, 2012.

Staff recommends the return on equity earnings test in conformance with Order No. 30978 issued in Case No. IPC-E-09-30 be adjusted as discussed above. The proposed adjustment results in a sharing with customers of $7,462,104.

Staff further recommends the $7.462 million sharing amount be used to reduce the Company-proposed DSM expense surcharge for the 2011-2012 PCA period.

Respectfully submitted this 17th day of May 2011.

Donald L. Howell, II
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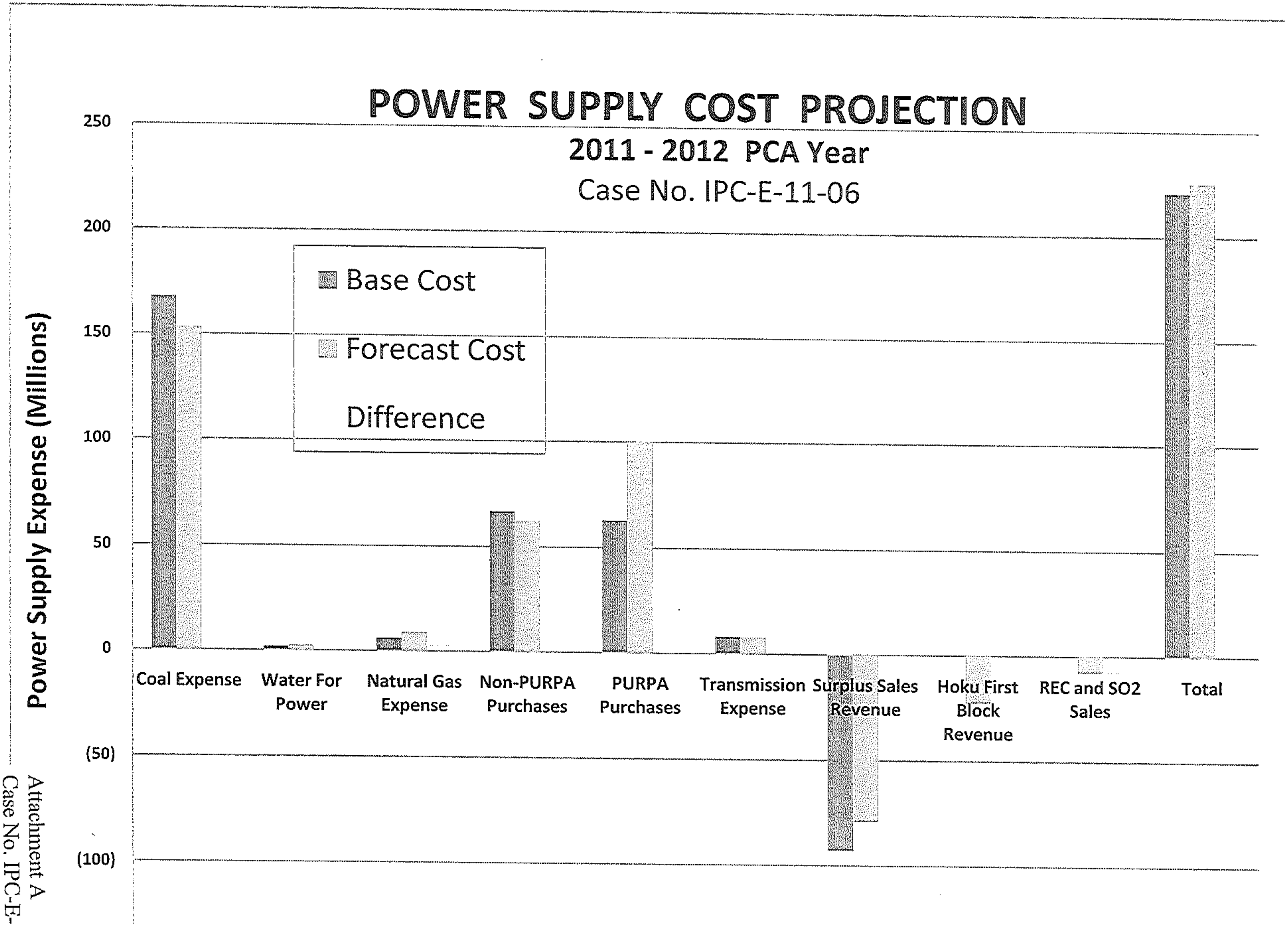


Attachment A
Case No. IPC-E-11-06
Staff Comments
5/17/11

2011-2012 PCA - Nineteenth Annual
IPC-E-11-06
Staff Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Projection 2011-2012:**					
2	PCA Expense (95%)	($)	157,918,683	155,654,432		
3	Hoku First Block Revenue Reduction	($)		(22,196,712)		
4	Renewable Energy Credits & SO2 Benefits	($)		(7,813,887)		
5	Difference	($)		125,643,833	(32,274,850)	
6	Sharing Percentage	(%)			0.95	
7	Shared Difference	($)			(30,661,108)	
8	Normalized System Firm Sales	(MWH)			14,147,195	
9	Rate for 95 % Items	(¢/kWh)			(0.2167)	(0.2167)
10						
11	PCA Expense (100%)	($)	62,851,454	99,801,054	36,949,600	
12	Normalized System Firm Sales	(MWH)			14,147,195	
13	Rate for 100% Items	(¢/kWh)			0.2612	0.2612
14						
15	Total Forecast Rate	(¢/kWh)				**0.0445**
16						
17						
18			($)	(MWh)	($/MWh)	(¢/kWh)
19						
20	**True-Up of 2010-2011:**		4,181,114			
21	SO2 Sales Credit		(491,740)			
22	Total True-Up		3,689,374	13,478,411	0.273724703	**0.0273**
23						
24	**True-Up of the True-Up:**		(18,152,667)	13,478,411	-1.346795776	**(0.1347)**
25						
26	**PCA Rates:**					
27	PCA Rate Adjustment From Base	(¢/kWh)				**(0.0629)**
28	PCA Rate Currently in Effect	(¢/kWh)				0.3114
29	Difference - Last Year to This Year	(¢/kWh)				(0.3743)
30						
31	Note: Negative rates and amounts indicate benefits to ratepayers.					

TRUE-UP CALCULATIONS FOR 2010 - 2011
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-11-06
Base Costs are Redistributed

1			2010	2010	2010	2010	2010	2010	2010
2	DESCRIPTION	Units	APR	MAY	JUN	JUL	AUG	SEPT	OCT
3	**PCA Revenue**								
4	Normalized Idaho Jurisd. Sales	MWh	968,949	998,195	1,123,624	1,316,280	1,400,447	1,280,168	1,033,366
5	Forecast Rate	$/MWh	4.967	4.967	1.404	1.404	1.404	1.404	1.404
6	Revenue	$	4,812,770	4,958,035	1,577,568	1,848,057	1,966,228	1,797,356	1,450,846
7									
8	**Load Change Adjustment**								
9	Actual System Firm Load - Adjusted	MWh	1,038,330	1,127,939	1,260,708	1,676,222	1,518,959	1,232,322	1,053,647
10	Normalized Firm Load	MWh	1,077,297	1,254,940	1,412,842	1,685,870	1,594,331	1,225,589	1,100,776
11	Load Change	MWh	(38,967)	(127,001)	(152,134)	(9,648)	(75,372)	6,733	(47,129)
12	Expense Adjustment	$	1,037,691	3,382,037	4,051,328	256,926	2,007,156	(179,300)	1,255,045
13									
14	**Non-QF PCA**								
15	ACTUAL:								
16	Water Leases	$	0	0	0	0	914,320	457,160	0
17	Fuel Expense - Coal	$	9,388,938	9,136,222	7,240,469	14,273,344	14,070,545	15,073,998	12,759,450
18	Fuel Expense - Gas	$	570,931	456,002	633,254	2,365,212	4,670,666	730,457	340,716
19	Non-Firm Purchases	$	3,057,227	2,261,341	8,319,121	18,739,777	15,878,714	3,809,004	1,801,892
20	Third Party Transmission	$	371,978	322,544	1,029,307	1,122,875	978,682	325,744	347,500
21	Surplus Sales	$	(4,452,277)	(8,213,149)	(4,500,060)	(2,908,250)	(2,977,706)	(5,109,310)	(3,670,472)
22	Hoku First Block Energy	$	(25,732)	(1,229)	0	0	0	0	0
23	Expense Adjustment	$	1,037,691	3,382,037	4,051,328	256,926	2,007,156	(179,300)	1,255,045
24	Sub-Total	$	9,948,755	7,343,767	16,773,419	33,849,886	35,542,379	15,107,753	12,834,131
25									
26	BASE:								
27	Water for Power (Leases)	$	4,734	4,664	153,090	190,953	204,643	179,325	133,942
28	Fuel Expense - Coal	$	9,357,518	9,219,352	14,041,049	17,513,694	18,769,296	16,447,224	12,284,817
29	Fuel Expense - Gas	$	429,483	423,141	507,539	633,064	678,450	594,515	444,057
30	Non-Firm Purchases	$	4,012,962	3,953,710	5,583,131	6,963,955	7,463,219	6,539,896	4,884,802
31	Third Party Transmission	$	734,112	723,272	691,679	862,746	924,599	810,211	605,165
32	Surplus Sales	$	(8,173,502)	(8,052,819)	(7,755,827)	(9,674,005)	(10,367,560)	(9,084,921)	(6,785,741)
33	Sub-Total	$	6,365,307	6,271,320	13,220,661	16,490,407	17,672,647	15,486,250	11,567,042
34									
35	Change From Base	$	3,583,448	1,072,447	3,552,758	17,359,479	17,869,732	(378,497)	1,267,089
36	Emission Allowance Sales Credit	$	0	0	0	0	0	0	0
37	Renewable Energy Credit Sales	$	(1,037,449)	10,739	(476,754)	506	(555,010)	(366,861)	(449,562)
38	Sub-Total	$	2,545,999	1,083,187	3,076,005	17,359,984	17,314,722	(745,358)	817,527
39									
40	Deferral (Shared and Allocated)	$	2,292,927	975,518	2,776,094	15,667,386	15,626,537	(672,685)	737,818
41									
42	**QF Deferral**								
43	Actual (includes Net Metering)	$	3,138,813	4,806,159	7,042,314	7,749,957	7,523,824	6,098,940	4,756,343
44	Base	$	4,436,330	4,370,826	5,261,808	6,563,163	7,033,693	6,163,509	4,603,670
45									
46	Change From Base	$	(1,297,517)	435,333	1,780,506	1,186,794	490,131	(64,569)	152,673
47	Deferral (Allocated)	$	(1,230,047)	412,696	1,691,481	1,127,454	465,624	(61,340)	145,040
48									
49	**Total Deferral** (-6+40+47)	$	(3,749,889)	(3,569,821)	2,890,007	14,946,783	14,125,934	(2,531,381)	(567,988)
50									
51	**Principal Balances**								
52	Beginning Balance	$	0	(3,749,889)	(7,319,710)	(4,429,703)	10,517,079	24,643,013	22,111,632
53	Amount Deferred	$	(3,749,889)	(3,569,821)	2,890,007	14,946,783	14,125,934	(2,531,381)	(567,988)
54	Ending Balance	$	(3,749,889)	(7,319,710)	(4,429,703)	10,517,079	24,643,013	22,111,632	21,543,643
55									
56	**Interest Balances**								
57	Accrual thru Prior Month	$	0	0	(3,125)	(9,225)	(12,916)	(4,148)	16,388
58	Interest @ 1% per Year	$	0	(3,125)	(6,100)	(3,691)	8,764	20,536	18,426
59	Prior Month's Interest Adj.	$	0	0	0	0	4	0	0
60	Total Current Month Interest	$	0	(3,125)	(6,100)	(3,691)	8,768	20,536	18,426
61	Interest Accrued to Date	$	0	(3,125)	(9,225)	(12,916)	(4,148)	16,388	34,814
62	**Balance (True-Up & Interest)**	$	(3,749,889)	(7,322,835)	(4,438,928)	10,504,163	24,638,865	22,128,019	21,578,457
63									
64	**True-Up of the True-Up**								
65	True-Up Revenues (Collections)	$	8,451,840	8,310,810	6,911,723	2,351,308	2,425,726	2,124,626	1,763,836
66									
67	Beginning Balance	$	11,284,407	14,815,717	6,302,048	(604,423)	(2,956,235)	(5,384,424)	(7,513,538)
68	Adjustments:								
69	2009-10 PCA Transfer - ON 31093	$	11,963,777	0	0	0	0	0	0
70	Emission Allowance - ON 30790	$	0	0		0	0	0	0
71	Interest Adjustment - O.N. 31093	$	0	(215,027)	0	0	0	0	0
72	Sub-Total	$	23,248,184	14,600,690	6,302,048	(604,423)	(2,956,235)	(5,384,424)	(7,513,538)
73	Interest @ 1% per Year	$	19,373	12,167	5,252	(504)	(2,464)	(4,487)	(6,261)
74	Revenue Applied to Interest	$	19,373	12,167	5,252	(504)	(2,464)	(4,487)	(6,261)
75	Revenue Applied to Balance	$	8,432,466	8,298,642	6,906,471	2,351,812	2,428,189	2,129,113	1,770,098
76	**True-Up of the True-Up Balance**	$	14,815,717	6,302,048	(604,423)	(2,956,235)	(5,384,424)	(7,513,538)	(9,283,635)
77									
78	Note: Negative amounts indicate benefit to ratepayers								

Attachment C
Case No. IPC-E-11-06
Staff Comments

TRUE-UP CALCULATIONS FOR 2010 - 2011
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-11-06
Base Costs are Redistributed

1			2010	2010	2011	2011	2011	
2	DESCRIPTION	Units	NOV	DEC	JAN	FEB	MAR	TOTALS
3	**PCA Revenue**							
4	Normalized Idaho Jurisd. Sales	MWh	958,498	1,074,126	1,193,372	1,115,947	1,029,368	13,492,340
5	Forecast Rate	$/MWh	1.404	1.404	1.404	1.404	1.404	
6	Revenue	$	1,345,731	1,508,073	1,675,494	1,566,790	1,445,233	25,952,179
7								
8	**Load Change Adjustment**							
9	Actual System Firm Load - Adjusted	MWh	1,134,671	1,264,561	1,295,294	1,105,065	1,117,888	14,825,606
10	Normalized Firm Load	MWh	1,130,765	1,380,118	1,356,320	1,177,732	1,160,140	15,556,720
11	Load Change	MWh	3,906	(115,557)	(61,026)	(72,667)	(42,252)	(731,114)
12	Expense Adjustment	$	(104,017)	3,077,283	1,625,122	1,935,122	1,125,171	19,469,566
13								
14	**Non-QF PCA**							
15	ACTUAL:							
16	Water Leases	$	0	0	215,600	(46,200)	514,305	2,055,185
17	Fuel Expense - Coal	$	13,666,802	15,252,103	12,440,921	8,622,590	6,942,649	138,868,030
18	Fuel Expense - Gas	$	972,484	441,024	665,501	546,640	528,630	12,921,516
19	Non-Firm Purchases	$	6,229,167	7,855,057	4,865,362	2,104,562	2,163,844	77,085,070
20	Third Party Transmission	$	206,220	243,884	286,977	251,821	324,477	5,812,011
21	Surplus Sales	$	(3,097,568)	(6,214,673)	(12,245,790)	(7,129,494)	(9,558,817)	(70,077,566)
22	Hoku First Block Energy	$	0	0	0	0	0	(26,961)
23	Expense Adjustment	$	(104,017)	3,077,283	1,625,122	1,935,122	1,125,171	19,469,566
24	Sub-Total	$	17,873,088	20,654,677	7,853,694	6,285,042	2,040,260	186,106,850
25								
26	BASE:							
27	Water for Power (Leases)	$	125,889	145,752	160,237	149,325	135,069	1,587,623
28	Fuel Expense - Coal	$	11,546,178	13,367,949	14,696,534	13,695,653	12,388,199	163,327,463
29	Fuel Expense - Gas	$	417,357	483,209	531,233	495,054	447,794	6,084,896
30	Non-Firm Purchases	$	4,591,097	5,315,486	5,843,770	5,445,791	4,925,909	65,523,728
31	Third Party Transmission	$	568,779	658,522	723,969	674,665	610,258	8,587,977
32	Surplus Sales	$	(6,377,740)	(7,384,028)	(8,117,896)	(7,565,042)	(6,842,846)	(96,181,927)
33	Sub-Total	$	10,871,560	12,586,890	13,837,847	12,895,446	11,664,383	148,929,760
34								
35	Change From Base	$	7,001,528	8,067,787	(5,984,153)	(6,610,404)	(9,624,123)	37,177,090
36	Emission Allowance Sales Credit	$	0	0	0	0	0	0
37	Renewable Energy Credit Sales	$	(474,280)	(435,465)	(614,204)	(500,119)	(750,662)	(5,649,119)
38	Sub-Total		6,527,247	7,632,322	(6,598,357)	(7,110,523)	(10,374,785)	31,527,971
39								
40	Deferral (Shared and Allocated)	$	5,890,841	6,888,171	(5,955,017)	(6,417,247)	(9,363,244)	28,447,098
41								
42	**QF Deferral**							
43	Actual (includes Net Metering)	$	4,167,831	4,411,185	5,122,518	5,186,222	4,788,369	64,792,474
44	Base	$	4,326,868	5,009,567	5,507,447	5,132,373	4,642,411	63,051,665
45								
46	Change From Base	$	(159,037)	(598,382)	(384,929)	53,849	145,958	1,740,809
47	Deferral (Allocated)	$	(151,085)	(568,463)	(365,683)	51,156	138,660	1,655,493
48								
49	**Total Deferral** (-6+40+47)	$	4,394,024	4,811,636	(7,996,194)	(7,932,880)	(10,669,816)	4,150,412
50								
51	**Principal Balances**							
52	Beginning Balance	$	21,543,643	25,937,667	30,749,303	22,753,109	14,820,229	
53	Amount Deferred	$	4,394,024	4,811,636	(7,996,194)	(7,932,880)	(10,669,816)	4,150,412
54	Ending Balance	$	25,937,667	30,749,303	22,753,109	14,820,229	4,150,412	
55								
56	**Interest Balances**							
57	Accrual thru Prior Month	$	34,814	52,767	74,382	100,008	118,969	
58	Interest @ 1% per Year	$	17,953	21,615	25,624	18,961	12,350	131,314
59	Prior Month's Interest Adj.	$	0	0	2	0	0	6
60	Total Current Month Interest	$	17,953	21,615	25,626	18,961	12,350	30,702
61	Interest Accrued to Date	$	52,767	74,382	100,008	118,969	131,319	
62	**Balance (True-Up & Interest)**	$	25,990,434	30,823,684	22,853,117	14,939,198	4,281,732	**4,181,114**
63								
64	**True-Up of the True-Up**							
65	True-Up Revenues (Collections)	$	1,566,524	1,854,932	1,942,056	1,757,907	1,694,293	41,155,581
66								
67	Beginning Balance	$	(9,283,635)	(10,857,896)	(12,721,876)	(14,674,534)	(16,444,669)	11,284,407
68	Adjustments:							
69	2009-10 PCA Transfer - ON 31093	$	0	0	0	0	0	11,963,777
70	Emission Allowance - ON 30790	$	0	0	0	0	0	0
71	Interest Adjustment - O.N. 31093	$	0	0	0	0	0	(215,027)
72	Sub-Total	$	(9,283,635)	(10,857,896)	(12,721,876)	(14,674,534)	(16,444,669)	23,033,156
73	Interest @ 1% per Year	$	(7,736)	(9,048)	(10,602)	(12,229)	(13,704)	
74	Revenue Applied to Interest	$	(7,736)	(9,048)	(10,602)	(12,229)	(13,704)	(30,242)
75	Revenue Applied to Balance	$	1,574,260	1,863,981	1,952,657	1,770,136	1,707,997	41,185,823
76	**True-Up of the True-Up Balance**	$	(10,857,896)	(12,721,876)	(14,674,534)	(16,444,669)	(18,152,666)	**(18,152,666)**
77								
78	Note: Negative amounts indicate benefit to ratepayers							

Attachment C
Case No. IPC-E-11-06
Staff Comments
5/17/11 Page 2 of 2

Idaho Power Company
Calculation of PCA Rate by Class
State of Idaho
Case No. IPC-E-11-06
Staff Proposal

Line No		Rate Schedule No	(1) Test Year Rider Applicable Revenue (1)	(2) Authorized DSM Rider Deferral Balance Recovery	(3) Test Year Billed kWh (1)	(4) DSM Recovery Rate Cents per kWh	(5) Uniform PCA Rate Cents per kWh	(6) Total PCA Rate Cents per kWh
1	Residential Service	1,3,4,5	$373,098,248	$1,164,112	4,997,560,536	0.0233	(0.0629)	(0.0396)
2	Small General Service	7	$14,215,377	$44,354	149,738,642	0.0296	(0.0629)	(0.0333)
3	Large General Service - Secondary	9S	$168,992,758	$527,278	3,105,385,167	0.0170	(0.0629)	(0.0459)
4	Large General Service - Primary	9P	$18,193,900	$56,767	401,521,169	0.0141	(0.0629)	(0.0488)
5	Large General Service - Transmissioi	9T	$113,461	$354	2,488,740	0.0142	(0.0629)	(0.0487)
6	Dusk to Dawn Lighting	15	$1,112,399	$3,471	6,562,095	0.0529	(0.0629)	(0.0100)
7	Large Power Service - Secondary	19S	$322,729	$1,007	7,166,303	0.0141	(0.0629)	(0.0488)
8	Large Power Service - Primary	19P	$80,418,370	$250,915	2,008,182,401	0.0125	(0.0629)	(0.0504)
9	Large Power Service - Transmission	19T	$1,639,317	$5,115	43,858,733	0.0117	(0.0629)	(0.0512)
10	Agricultural Irrigation Service	24	$101,574,213	$316,924	1,679,705,737	0.0189	(0.0629)	(0.0440)
11	Unmetered General Service	40	$1,046,755	$3,266	16,000,941	0.0204	(0.0629)	(0.0425)
12	Street Lighting	41	$2,742,058	$8,556	23,018,849	0.0372	(0.0629)	(0.0257)
13	Traffic Control Lighting	42	$157,859	$493	3,477,113	0.0142	(0.0629)	(0.0487)
14	Total Uniform Tariffs		$763,627,444	$2,382,611	12,444,666,426			
15	Special Contracts:							
16	Micron	26	$16,000,606	$49,924	466,741,299	0.0107	(0.0629)	(0.0522)
17	J R Simplot	29	$5,802,147	$18,103	180,758,797	0.0100	(0.0629)	(0.0529)
18	DOE	30	$7,988,553	$24,925	251,548,881	0.0099	(0.0629)	(0.0530)
19	Hoku	32	$19,977,510	$62,332	134,695,800	0.0463	(0.0629)	(0.0166)
20	Total Special Contracts		$49,768,816	$155,285	1,033,744,777			
21	Total Idaho Jurisdiction		$813,396,260	$2,537,896	13,478,411,203			

(1) June 1, 2011 through May 31, 2012 forecasted test year

Idaho Power Company
Summary of Revenue Impact
State of Idaho
Forecasted 12-Months Ending May 31, 2012
Staff Proposal

Present Billed Rates to 6/1/2011 Billed Rates (PCA & DSM Recovery)

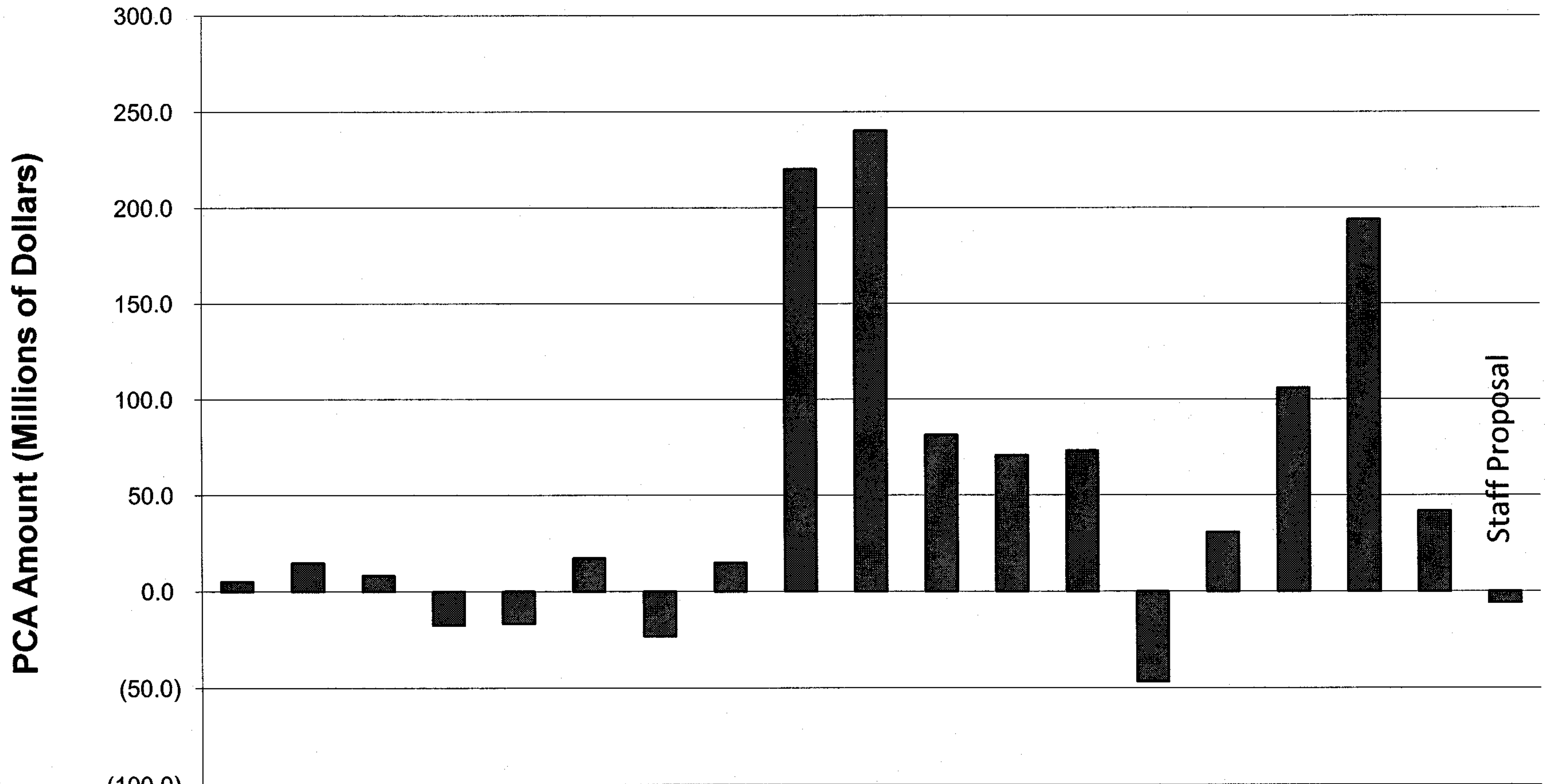
Line No	Tariff Description	(1) Rate Sch. No.	(2) Average Number of Customers	(3) Normalized Energy (kWh)	(4) Current Billed Revenue	(5) Billed Revenue Adjustments	(6) Proposed Billed Revenue	(7) Average ¢/kWh	(8) Percent Change
1	Uniform Tariff Rates:								
2	Residential Service	1	398,890	4,990,482,967	$394,209,984	($17,516,595)	$376,693,389	7.548	-4.44%
3	Master Metered Mobile Home Park	3	22	5,160,634	$388,537	($18,114)	$370,423	7.178	-4.66%
4	Residential Service Energy Watch	4	42	741,745	$57,719	($2,604)	$55,115	7.430	-4.51%
5	Residential Service Time-of-Day	5	74	1,175,190	$91,440	($4,125)	$87,315	7.430	-4.51%
6	Small General Service	7	28,258	149,738,642	14,911,514	(516,149)	$14,395,365	9.614	-3.46%
7	Large General Service	9	31,067	3,509,395,076	198,228,379	(12,550,782)	$185,677,597	5.291	-6.33%
8	Dusk to Dawn Lighting	15	-	6,562,095	1,132,831	(21,091)	$1,111,740	16.942	-1.86%
9	Large Power Service	19	115	2,059,207,437	88,792,784	(7,450,449)	$81,342,335	3.950	-8.39%
10	Agricultural Irrigation Service	24	16,710	1,679,705,737	106,804,816	(5,969,674)	$100,835,142	6.003	-5.59%
11	Unmetered General Service	40	1,984	16,000,941	1,096,581	(56,627)	$1,039,954	6.499	-5.16%
12	Street Lighting	41	314	23,018,849	2,813,736	(77,597)	$2,736,139	11.887	-2.76%
13	Traffic Control Lighting	42	358	3,477,113	168,689	(12,521)	$156,168	4.491	-7.42%
14	*Total Uniform Tariffs*		477,834	12,444,666,426	$808,697,010	($44,196,328)	$764,500,682	6.143	-5.47%
15									
16	Special Contracts:								
17	Micron	26	1	466,741,299	$17,454,039	(1,697,071)	$15,756,968	3.376	-9.72%
18	J R Simplot	29	1	180,758,797	6,365,029	(658,504)	$5,706,525	3.157	-10.35%
19	DOE	30	1	251,548,881	8,771,875	(916,644)	$7,855,231	3.123	-10.45%
20	Hoku	32	1	134,695,800	5,703,826	(441,802)	$5,262,024	3.907	-7.75%
21	*Total Special Contracts*		4	1,033,744,777	38,294,769	(3,714,021)	34,580,748	3.345	-9.70%
22									
23									
24	***Total Idaho Retail Sales***		477,838	13,478,411,203	$846,991,779	($47,910,349)	$799,081,430	5.929	-5.66%

Power Supply Cost Summary
IPC-E-11-06
Base Costs are Redistributed

Description	Projection or Actual ($)	Base ($)	Difference or Initial Amount ($)	Allocated to Other Jurisdictions ($)	Shared with Shareholders ($)	Idaho Customer Revenue Requirement ($)	**Idaho PCA Rates (¢/kWh)**
Forecast or Projection (2011-2012)	Projection	Base	Difference				
Acct. 501 - Coal	153,268,673	167,718,084	(14,449,411)	(722,471)	(686,347)	(13,040,593)	
Acct. 536 - Water for Power	2,291,000	1,828,640	462,360	23,118	21,962	417,280	
Acct. 547 - Natural Gas	8,971,778	6,062,472	2,909,306	145,465	138,192	2,625,649	
Acct. 555 - Purchased Power (Non- PURPA)	62,308,530	66,689,601	(4,381,071)	(219,054)	(208,101)	(3,953,917)	
Acct. 555 - Purchased Power (PURPA)	99,801,054	62,851,454	36,949,600	1,847,480	0	35,102,120	
Acct. 565 - Transmission Wheeling	7,897,586	8,262,000	(364,414)	(18,221)	(17,310)	(328,884)	
Acct. 447 - Opportunity Sales Revenues	(79,083,135)	(92,642,114)	13,558,979	677,949	644,052	12,236,979	
Hoku First Block Energy Revenue	(22,196,712)	0	(22,196,712)	(1,109,836)	(1,054,344)	(20,032,533)	
REC and SO2 Sales	(7,813,887)	0	(7,813,887)	(390,694)	(371,160)	(7,052,033)	
Sub-Total	225,444,887	220,770,137	4,674,750	233,738	(1,533,055)	5,974,068	**0.0445**
True Up (2010-2011)	Actual	Base	Difference				
Revenue from Forecast Rate	25,952,179	0	(25,952,179)	0	0	(25,952,179)	
Acct. 501 - Coal	138,868,030	163,327,463	(24,459,433)	(1,223,075)	(1,161,818)	(22,074,540)	
Acct. 536 - Water for Power	2,055,185	1,587,623	467,562	23,359	22,210	421,993	
Acct. 547 - Natural Gas	12,921,516	6,084,896	6,836,620	342,180	324,722	6,169,719	
Acct. 555 - Purchased Power (Non- PURPA)	77,085,070	65,523,728	11,561,342	572,771	549,429	10,439,142	
Acct. 555 - Purchased Power (PURPA)	64,792,474	63,051,665	1,740,809	85,316	0	1,655,493	
Acct. 565 - Transmission Wheeling	5,812,011	8,587,977	(2,775,966)	(140,324)	(131,782)	(2,503,860)	
Acct. 447 - Opportunity Sales Revenues	(70,077,566)	(96,181,927)	26,104,361	1,312,340	1,239,601	23,552,420	
Load Change Adjustment	19,469,566	0	19,469,566	982,318	924,362	17,562,886	
Hoku First Block Energy Revenue	(26,961)	0	(26,961)	(1,402)	(1,278)	(24,281)	
REC Sales	(5,649,119)	0	(5,649,119)	(284,509)	(268,230)	(5,096,379)	
Interest During Deferral Period	30,702	0	30,702	0	0	30,702	
Sub-Total	271,233,087	211,981,425	7,347,303	1,668,973	1,497,216	4,181,114	
SO2 Credit (External Adjustment)						(491,740)	
Sub-Total						3,689,374	**0.0273**
True Up of the True Up (Reconciliation of the True Up)			Initial Amount				
Unrecovered True Up of the True Up Amount Carried Forward			11,284,407			11,284,407	
Other Limited Term Adjustments:							
2009-2010 PCA True Up Amount Transferred (ON 31093, IPC-E-10-12)			11,963,777			11,963,777	
Emission Allowance			0			0	
Interest Adjustment (ON 31093, IPC-E-10-12)			(215,027)			(215,027)	
Interest During Amortization			(30,242)			(30,242)	
Revenue from True Up & True Up of the True Up Rates			(41,155,581)			(41,155,581)	
Sub-Total			(18,152,666)	0	0	(18,152,666)	**(0.1347)**
Total Power Cost Adjustment (PCA)							**(0.0629)**

Attachment F
Case No. IPC-E-11-06
Staff Comments
5/17/11

HISTORY OF PCA AMOUNTS



	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
■PCA Amounts	4.9	14.7	8.1	(17.6)	(16.7)	17.3	(23.2)	14.8	220.2	240.2	81.3	70.8	73.1	(46.8)	30.7	106.0	194.0	41.9	(5.9)

PCA Year

Attachment G
Case No. IPC-E-11-06
Staff Comments
5/17/11

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS **17TH** DAY OF MAY 2011, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-11-06, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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Glenda D. Koch
SECRETARY