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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2017 THROUGH MAY 31, 2018.	**CASE NO. IPC-E-17-06** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Brandon Karpen, Deputy Attorney General, and in response to the Notice of Modified Procedure and Notice of Comment Deadline issued in Order No. 33755 on April 26, 2017, in Case No. IPC-E-17-06 to submit the following comments.

BACKGROUND

On April 14, 2017, Idaho Power Company applied to the Commission for an Order authorizing the Company to adjust its Schedule 55 PCA rates. The Company's PCA Application, if approved, would increase overall revenue collected from Customers by about $10.6 million or 0.93%. The Company requested that the new rates take effect on June, 1, 2017.

The Commission first approved the annual PCA mechanism in 1993, and it has been modified several times since then. *See* Commission Order Nos. 30715, 30978, 32206, 32424, 33149, 33307. The Company's actual cost to provide electricity (Net Power Supply Expense, or NPSE) varies from year-to-year depending on changes in stream flows, the amount of purchased power, fuel costs, the market price of power, and other factors. The PCA mechanism tracks annual differences between actual NPSE and NPSE recovered through base rates. The PCA is also used to provide revenue sharing benefits resulting from the revenue sharing mechanism approved in Order No. 33149 and has historically provided an annual DSM Rider credit per Order No. 33000. In this year's PCA, earnings were not sufficient to provide customers with a revenue sharing credit; and per Commission Order No. 33736, the DSM Rider credit is no longer applicable. However, the Order does provide a one-time refund of unspent DSM Tariff Rider Revenue collected by the Company.

STAFF REVIEW

Staff reviewed and audited the traditional PCA components (forecast, true-up, and reconciliation of the true-up) and additional components applied in the PCA (Revenue Sharing and DSM Rider Refund). Staff also reviewed the spread of incremental PCA revenue across customer classes for both the traditional PCA components and the additional components in this year's PCA. Staff's major findings as a result of its review are summarized as follows.

1. The assumptions used in the Company's forecast reasonably approximate cost of operations in the next year's deferral period (June 1, 2017, through May 30, 2018) providing collections that should approximate the difference in actual NPSE and NPSE recovery through base rates.
2. Although the Company had major equipment and facility downtime, Staff believes there was not enough evidence to conclude that the Company was able to prevent it. The Company made efforts to minimize its impact, and therefore, prudently incurred actual NPSE during the deferral period.
3. Actual and base costs, revenues, and loads used to calculate the revenue requirement were found to be accurate.
4. The methods used to calculate the revenue requirement for all components of the PCA (including the forecast, the true-up, the reconciliation of the true-up, revenue sharing, and the DSM Rider refund) were accurate and complied with past Commission orders.
5. The methods used to determine the allocation of the revenue requirement across customer classes were found to be fair and reasonable.

Through the PCA, Idaho Power Company is requesting an increase of about $10.6 million or 0.93% more in total revenue above what it is currently collecting through customer rates. Current Schedule 55 PCA rates are designed to collect about $79.5 million in annual revenue from June 1, 2016, through May 30, 2017. The Company's request would increase that amount to $90.1 million, which would be a 13.3% increase in Schedule 55 rates. The following table provides a breakdown of the increase.

Table 1: Idaho Power Proposed Customer Revenue Impact

Description	Current ($)	Proposed ($)	Difference ($)	% Increase	% of Total
PCA Future Forecast	47,943,199	66,914,308	18,971,109	39.57%	179%
PCA True Up (includes reconciliation of True-up)	38,738,441	36,210,680	(2,527,761)	-6.53%	-24%
Allocated Revenue Sharing	(3,155,010)	-	3,155,010	100.00%	30%
Associated DSM Rider Change	(3,985,530)	-	3,985,530	100.00%	38%
DSM rider Refund	-	(13,000,000)	(13,000,000)	n/a	-123%
PCA Total	**79,541,100**	**90,124,988**	**10,583,888**	**13.31%**	**100%**
Total Billed Revenue	**1,134,056,319**	**1,144,644,933**	**10,588,614**	**0.93%**	

As shown above, the PCA future forecast component has the largest impact on the Company's requested amount. The PCA forecast is about $19 million (39.6%) higher than the forecast used in last year's PCA and 179% of the Company's total requested increase. However, a one-time $13 million DSM Rider refund being issued in this year's PCA along with a $2.5 million reduction in the True-up has substantially lessened that increase. The absence of a revenue sharing credit, and the discontinuation of the annual DSM Rider credit in this year's PCA make up the remaining increase.

The overall rate impact for the largest customer classes are provided in the following table. A copy of Company Attachment 2 showing the impact of proposed rates for all customer classes is included as Attachment A to these Comments.

Table 2: Overall Rate Impact

Class Description	Rate Schedule	% Increase
Residential	1	0.58%
Small General Service	7	0.27%
Large General Service	9	1.12%
Large Power Service	19	1.65%
Irrigation	24	0.94%
Micron	26	1.95%
JR Simplot	29	2.16%
DOE	30	2.03%
Overall Increase		**0.93%**

Details of Staff's analysis of the Traditional PCA components, Revenue Sharing, DSM Rider funds, and calculation of rates are discussed in the following sections.

Traditional PCA Components

The traditional annual PCA mechanism has three components: (1) a "forecast" or projection that estimates the difference between NPSE embedded in base rates and the coming year's NPSE; (2) a "true-up" that captures the difference between actual and base NPSE and credits the revenue from the previous year's collected forecast rate; and (3) a reconciliation of the prior year's true-up that captures any under-recovered or under-refunded true-up amount. The reconciliation is also called the "true-up of the true-up."

The Company combined the three traditional PCA rate components and proposed a 2017 PCA rate surcharge of 0.7361 cents per kilowatt-hour (¢/kWh) (i.e., 0.4776 + 0.2423 + 0.1611). The Company expects this rate will allow it to recover the traditional PCA ending balance at the end of the coming year. The proposed rate is 0.1174 ¢/kWh higher than current PCA rates. Each component is described in more detail below.

To produce the forecast, the Company used its March 31, 2017, Operating Plan to forecast NPSE for the coming year and determined the difference between these amounts and NPSE embedded in base rates. The Company reported Idaho ratepayers' share of the difference is about $47.8 million. This difference was then converted into a ¢/kWh rate by dividing the amount by projected energy sales. The Company proposed a 0.47760 ¢/kWh forecast rate as compared to a 0.3422 ¢/kWh rate in last year's PCA.

The true-up amount is primarily made up of the differences between actual NPSE and NPSE recovered through base rates, and revenues from the forecast rate that accrued during the prior year. The prior year's PCA amount is not precisely recovered, because the expected cost forecast can never be 100% accurate. The Company converts the true-up amount to a ¢/kWh rate by dividing it by projected energy sales. The Company calculates Idaho ratepayers' share of the true-up amount to be $34.0 million, and expects to recover that amount through a true-up rate of 0.2423 ¢/kWh as compared to last year's rate of 0.3129 ¢/kWh. A copy of Company Exhibit 1, which details the Company's true-up calculations, is reproduced as Attachment B to these Comments.

The reconciliation of the true-up tracks the recovery of the prior year's true-up amounts. It nets the actual revenue collected from the true-up rates, and revenue-sharing rates against the amounts set for recovery. Any difference is carried into the next year's true-up reconciliation along with the true-up difference. According to the Company, the true-up was under-collected by about $2.3 million, resulting in a proposed reconciliation of the true-up rate of 0.1611 ¢/kWh as compared to a credit of 0.0364 ¢/kWh in last year's PCA.

Staff's analyses of the three traditional PCA components are described in the following sections.

Forecast Analysis

The Company's system level NPSE forecast for the 2017-2018 PCA year is $377,451,633, which is $71,766,764 higher than the currently approved base level NPSE of $305,684,869. The Company determined that the 2017-2018 PCA forecast component to be collected from Idaho jurisdictional customers over the next year is $66,914,308. Staff believes the Company's forecast reflects reasonable future conditions and recommends the Commission accept the new forecasted PCA rate of 0.4776 cents per kWh.

As noted previously, the PCA forecast rate accounts for 179% of the projected $10.6 million revenue increase and is about 40% higher than last year's forecast. However, Staff believes this reasonable when comparing 2016-2017 actual NPSE with the Company's proposed forecast. Although actual NPSE during the 2016-2017 deferral period as shown in Table 3 below is about $50.3 million or 12% higher than the Company's forecast in this case, the Company's forecast is roughly equal to last year's actual cost after accounting for extraordinary circumstances that occurred during the 2016-2017 deferral period. These circumstances include a significant increase in PURPA capacity that came online during the 2016-2017 deferral period, an increase in the cost of coal generation due to increased mining cost during the deferral period, and below average water for hydro generation that is expected to increase surplus sales and reduce purchases this coming year. Each of these are discussed in more detail below.

Table 3: 2017 Forecast versus 2016-2017 Actual

FERC Account	2016-2017 Actual	2017-2018 Forecast	$ Difference	% Difference
Surplus Sales	$ (25,768,277)	$ (34,371,858)	$ (8,603,581)	-33%
Coal	$ 141,879,874	$ 126,769,503	$ (15,110,371)	-11%
Other Fuel (Gas)	$ 37,820,518	$ 37,305,583	$ (514,936)	-1%
Purchased Power Non-PURPA	$ 79,009,662	$ 52,615,287	$ (26,394,375)	-33%
PURPA	$ 181,714,395	$ 181,714,395	$ -	0%
DR Incentives	$ 7,059,424	$ 7,401,698	$ 342,274	5%
3rd Party Transmission	$ 6,017,025	$ 6,017,025	$ -	0%
Total	$ 427,732,621	$ 377,451,632	$ (50,280,989)	-12%

The largest impact in the Company's PCA forecast is a $23 million increase in PURPA-related costs (See Table 4 below) above last year's forecast. It is driven by an approximate 340 MW increase of PURPA wind and solar capacity in combination with about a $40 per MWh cost difference as compared to market prices.[1] Because PURPA generation is a must-buy obligation, the Company has no choice but to accept increases in PURPA-related NPSE. As a result, Staff believes it is proper to use last year's actual PURPA NPSE in its forecast as shown in Table 3, above.

Table 4: 2017 Forecast versus 2016 Forecast

FERC Account	2016-2017 Forecast	2017-2018 Forecast	$ Difference	% Difference
Surplus Sales	$ (20,930,147)	$ (34,371,858)	$ (13,441,711)	-64%
Coal	$ 112,127,106	$ 126,769,503	$ 14,642,397	13%
Other Fuel (Gas)	$ 39,202,822	$ 37,305,583	$ (1,897,239)	-5%
Purchased Power Non-PURPA	$ 54,988,467	$ 52,615,287	$ (2,373,180)	-4%
PURPA	$ 158,758,382	$ 181,714,395	$ 22,956,013	14%
DR Incentives	$ 7,401,698	$ 7,401,698	$ -	0%
3rd Party Transmission	$ 5,999,412	$ 6,017,025	$ 17,613	0%
Total	$ 357,547,740	$ 377,451,632	$ 19,903,892	6%

The second largest increase to the PCA forecast is due to a 13% increase in coal generation NPSE above last year's PCA forecast as reflected in Table 4. According to the Company, the cause of the increase is from increased coal cost from Bridger Coal Company due

[1] Average cost of PURPA generation is $62.42 per MWh versus predicted average market prices of $23.46. *See* Blackwell DI, at 11.

to the Joy Longwall mining equipment collapse and reduced Bridger generation during the 2017-2018 deferral period. This could result in a 18% increase in the per ton cost of coal caused by accelerated depreciation of equipment losses, mine recovery costs, and reduced economies of scale from lower coal production. *See* Company Response to ICIP Production Request No. 6. Staff finds it reasonable that with larger amounts of must-take PURPA generation and higher coal generation costs as compared to other resources, the amount of coal generation will trend downward. Given these trends, Staff believes that an 11% decrease in coal generation cost as compared to actual cost during the deferral period is reasonable.

The Company is expecting higher surplus sales and reduced purchases due to a projected increase in the amount of hydro generation for the 2017-2018 deferral period. *See* Blackwell, DI at 10. The Company projects a $13.4 million increase in surplus sales compared to last year's forecast (Table 4) and an $8.6 million increase compared to actual surplus sales during the deferral period (Table 3). Similarly, increased amounts of hydro generation should reduce the amount of Non-PURPA purchases as reflected in Table 3. The increase in surplus sales benefits customers because it offsets increases in coal fuel expenses and PURPA obligations. Although surplus sale prices are forecasted to decline by 14% to $15.88 per MWh in the coming year, Staff believes an increase in surplus sales volume and a decrease in system purchases as a result of more abundant hydro generation is reasonable. Any changes to the forecast will be trued-up in the following year.

True-Up Analysis

The Company's PCA true-up primarily reflects the difference between NPSE collected through base rates and actual NPSE incurred during the deferral period of April 1, 2016, through March 31, 2017. The ending balance also includes collections through the current forecast PCA rate and monthly accrued interest. Table 5, below, summarizes the $33,953,028 true-up amount that forms the Company's proposed true-up revenue requirement for Idaho.

Staff's review of the true-up included: (1) an on-site audit of the various components included in the true-up or deferral balance; (2) an analysis of the methods and basis used to calculate the cost deferrals and account balances; and (3) a review of actual NPSE including monthly Risk Management Committee minutes, operating plans, and other reports that were presented to the Risk Management Committee. As a result of its review, Staff concludes the

Company's proposed true-up amount is accurate. The methods used conform to past Commission Orders and actual costs incurred are reasonable and prudent.

Table 5: PCA True-Up Summary

Positive numbers are a cost to customers negative numbers are a benefit to customers.

Net Power Supply Expense Differential	**Deferral Amount**
Water Leases	$ (2,148,489)
Fuel Expense - Coal	30,531,554
Fuel Expense - Gas	4,147,758
Surplus Sales	23,379,392
Non-Firm Purchases	14,954,520
Third Party Transmission Expense	77,805
Subtotal - Net Power Supply Expense	70,942,540
Renewable Energy Credit (REC) Sales	(1,293,025)
Sales Based Adjustment	(6,843,374)
Qualifying Facilities	20,619,776
Demand Response Incentive Payments	(4,192,841)
Total Expense Items	79,233,076
Revenue from PCA Forecast	45,487,126
Deferral Balance (Expense Items less PCA Forecast Revenue)	33,745,949
Interest on the Deferral Balance	207,079
Total True-Up Deferral	$33,953,028

Details of the different components in the PCA true-up, as shown in Table 5, are described below.

Net Power Supply Expense Differential

Staff believes the Company prudently incurred NPSE to meet customer load. The Company's NPSE primarily consist of costs related to coal and other fuels, non-PURPA purchased power, and surplus sales. During the 2016/2017 PCA year, reduced availability of hydro generation required the Company to increase power generation from coal and other fuels, and to increase purchases from other non-PURPA sources. Further, surplus sales declined as a result of reduced hydro generation, and lower overall market prices. The main NPSE components are described below.

1. *Water Leases.* The Company occasionally leases water to produce hydro power. There is $2,380,597 included in base NPSE for water leases. Any deviation from the amount included in base rates either increases or decreases the PCA deferral. This year the Company did not incur any water lease expenses. After jurisdictional allocation and sharing, $2,148,489 is returned to customers as an offset to the deferral balance.
2. *Fuel Expense - Coal*. The Company owns an interest in and receives electricity from three coal plants: Bridger, Valmy and Boardman. The Company includes the increase or decrease in coal expense from base rates in the PCA for recovery from or a credit to customers. From April 2016 through March 2017, the total coal expense for the three plants was $141,879,874. The total coal expense included in base rates is $108,503,180. This year's PCA deferral balance, after jurisdictional allocation and sharing, includes a difference of $30,531,554 for recovery.

   Coal expenses during the PCA period increased for several reasons. There was a reduction of coal deliveries from the Bridger Coal Company mine to the Bridger power plant. The original budget included 5.9 million tons of deliveries to Bridger for calendar year 2016. Due to lower market prices, natural gas prices, and the abundance of renewable generation, the total budgeted output from Bridger was reduced in the first quarter of 2016. This reduction in the planned output from the Bridger power plant translated into a reduction in the delivery of coal from a budgeted 5.9 tons to 4.2 million tons, thus reducing the delivered tons to the plant and increasing the cost per ton. In other words, the fixed costs of the coal were spread over a lower tonnage which increased the unit price for fuel at the plant.

   In addition to lower production, coal costs also increased due the abandonment of the Joy Longwall mining system by the Bridger Coal Company. The Joy Longwall equipment was operational until December 2015 when it was halted by soft incompetent clay floor and steep floor grades, a thinning coal seam, and uncontrollable caving. Recovery attempts were halted in early October 2016, when safety concerns prompted the Bridger Coal Company to abandon the equipment. The costs for the attempted recovery and abandonment of the Joy Longwall equipment are included in the fuel cost calculations. Staff reviewed the coal costs recorded in

September 2016 and trued-up in October 2016 related to the Joy Longwall abandonment and believes the net book value of $6.25 million (Idaho Power's share) to be appropriate. The continuing recovery efforts in the amount of $3.64 million (Idaho Power's share) from December 2015 through October 2016 were included in the appropriate FERC account by the Bridger Coal Company, and end up included in the monthly cost of coal burned.

Another driver of the increased fuel expense at Bridger is related to the decreased coal production at the Bridger Coal Company underground mine. The Joy Longwall equipment was not mining coal from January through the abandonment in October. The DBT Longwall was put back into service in August 2016, but extracted in November 2016. Because there was no Longwall production at the underground mine for the majority of the year, fixed costs related to the underground mining operations were spread over a relatively small amount of underground tons. The 2016 budgeted tonnage was 3,495,200 tons and actual tonnage was 1,718,300 tons. Commission Staff, in its audit of the coal expenses, reviewed all months of coal expenses, with an in-depth audit of the months of July 2016, September 2016, and December 2016.

Staff met with Company officials to discuss the Joy Longwall abandonment and impact on coal costs. As a result of the meeting, and after reviewing the response to discovery, Staff believes that the Joy Longwall recovery efforts and subsequent abandonment was an unforeseen event and that the costs were prudently incurred. Staff notes that during the period of the Joy Longwall recovery and subsequent abandonment, coal production at the surface mine continued and there was no shortage of coal as a result of the incident. Staff is satisfied that the Company took the necessary precautions to contain this incident, including the geologic steps necessary to ascertain the conditions of the section of the mine that encompassed the Joy Longwall failure.

Staff also evaluated establishing a regulatory account to amortize the attempted recovery costs and abandonment costs for ratemaking purposes. The Company's proposed treatment is in compliance with Generally Accepted Accounting Principles, recovery through the PCA results in Idaho Power absorbing

5% of the cost, and it is consistent with the proposed treatment for PacifiCorp, the operating partner of Bridger. Therefore, Staff believes the proposed treatment is reasonable and does not propose an adjustment to the fuel expense for coal in this PCA.

3. *Fuel Expense - Gas.* The Company owns and operates gas-fired combustion turbine generating plants at the Evander Andrews Power Complex (3 Danskin units), Bennett Mountain, and Langley Gulch. Staff reviewed the natural gas purchases in conjunction with the Company's Operating Plan. Staff reviewed all months of the natural gas expenses included in the PCA period and performed an in-depth audit of the months of September 2016 and January 2017. The transactions appear reasonable and follow the Risk Management Committee's recommendations.

   From April 2016 through March 2017, the total variable gas and gas transportation expense for all the gas plants was $37,820,518. The total gas and gas transportation expense included in base rates is $33,367,563. This year's PCA deferral balance, after jurisdictional allocation and sharing, is an increase of $4,147,758.

   Notably, the Langley Gulch facility experienced a longer than anticipated maintenance outage - from October 24, 2016, through December 15, 2016. The scheduled maintenance outage was planned for a hot gas path inspection on the gas turbine and to replace the steam turbine seal and set to end on November 30, 2016. The outage was extended due to turbine rotor seal wear, found during inspection. After the routine fall outage was extended, there were three additional unplanned outages in December, in part due to additional maintenance that was required and complications from the cold weather.

   Upon Staff's request, the Company estimates that the incremental cost of the replacement power for the Langley Gulch outage was $733,532. This estimate reflects Langley Gulch generation being replaced with approximately 16,507 MW of generation at its Danskin facility and 105,692 MW of purchased power from the market. Staff believes that the Company took appropriate actions to mitigate the length and the cost of the outage, and therefore does not propose to exclude any costs in the PCA period as a result of the extended Langley outage.

Although Staff does not believe the extended outage was preventable, the Company was not able to provide the root cause of the unplanned outage associated with the steam turbine rotor seal wear or the cold weather complications. The Company indicated that the results of its root cause analysis will not be available until after this case is settled. Staff recommends that the Company provide the Commission with a copy of its root cause analyses as a subsequent compliance filing to this case.

4. *Surplus Power Sales.* To supplement its own generation, the Company purchases power in the wholesale market based on the Energy Risk Management Policy requirements, operating reserve margins, unit availability and economics. When the Company has excess power or generating capacity and economics dictate, the Company also sells power into the wholesale markets. During the PCA period, the Company made wholesale market purchases at an average price of $38.05 per MWh, and surplus sales at an average price of $17.98 per MWh. Base rates include wholesale market purchases at an average price of $50.64 per MWh, and surplus sales at an average price of $22.41 per MWh.

Market purchases and sales are influenced by many things. Economic conditions and regulations can affect the market price of natural gas and coal, which may then impact market prices for power. Natural gas prices have been, and continue to be, low relative to years past, and strongly influences the price of power on the wholesale market. Decreased hydro generation can also decrease the amount of surplus sales.

Staff reviewed the Company's power sales and purchases in conjunction with the Company's Operating Plan. Staff reviewed all the sales and purchases, and performed an in-depth audit of select transactions for each PCA month. Staff compared the term purchase or sale price to the forward market prices from the monthly Operating Plans and compared the day-ahead and real-time market prices to the ICE (Intercontinental Exchange) Mid-C daily price index. The transactions appear reasonable and follow the Risk Management Committee's recommendations. These transactions were made with an assortment of credit-worthy partners on a timely basis.

During the PCA year ending March 31, 2017, the Company's off-system sales of surplus power totaled \$25,768,277. The total surplus sales included in base rates is \$51,735,153. After jurisdictional allocation and sharing, actual surplus sales were less than base amounts by \$23,379,392, which increases the deferral balance to be recovered from customers.

5. *Non-Firm Power Purchases*. Excluding PURPA purchases during the PCA year ending March 31, 2016, the Company bought \$79,009,662 of power on the market. The power purchases included the output from the Neal Hot Springs Power Purchase Agreement, with a 25-year levelized contract price of approximately \$117.56/MWh; and the Elkhorn (Telocaset Wind Power Partners, LLC) Power Purchase Agreement, with a 20-year levelized contract price of approximately \$62.38/MWh. Base rates included \$62,606,593 in non-PURPA power purchases. After jurisdictional allocation and sharing, actual non-PURPA power purchases exceeded base amounts by \$14,954,520. This increases the deferral balance to be recovered from customers.
6. *Third-Party Transmission*. In Order No. 30715, the Commission directed the Company to track third-party transmission costs associated with market purchases and off-system sales 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 April 2016 through March 2017 PCA period, the actual third-party transmission expense is \$5,522,758. The third-party transmission expense included in base rates is \$5,455,955. After jurisdictional allocation and sharing, third-party transmission expense increases the deferral balance by \$77,805.

Other PCA Expense Items

7. *Renewable Energy Credit Sales*. In Order No. 30818, the Commission ordered that revenues from the sale of renewable energy credits ("RECs") should benefit customers. The deferral balance includes \$1,293,075 in revenue from REC sales, after allocation and sharing. This increase in revenues decreases the deferral balance recovered from customers.

Staff reviewed the REC transactions included in the PCA deferral period and verified that the amount included in the deferral period is accurate. During Staff's audit of the wholesale market purchases and sales, Staff discovered a wholesale market purchase and off-setting wholesale market sale that included a sale of RECs. Although the wholesale market purchase and sale occurred within the current PCA deferral period, the RECs did not settle until after the current PCA period had ended. The REC revenue from this transaction will be included in next year's deferral period. Staff recommends that the REC revenue be recorded with the corresponding wholesale market sale in future PCA periods.

8. *Sales-Based Adjustment*. The Company calculates a $6,843,374 Sales Based Adjustment (SBA) credit to customers from the Company's over-recovery of actual NPSE collected through base rates due to differences in base versus actual sales. The SBA replaced the Load Change Adjustment used in previous PCAs. The SBA uses the $26.72/MWh SBA rate established in Order No. 33307 (Case No. IPC-E-15-15). When multiplied by the difference in actual and base rate sales, it calculates the over or under recovery of actual NPSE due to sales that are higher or lower than sales used to determine base rates (subject to 95% customer sharing). During the April 2016 through March 2017 PCA deferral period, actual sales were 269,594 MWh higher than sales used to set base rates, resulting in a credit back to customers. Staff audited and analyzed the Company's SBA calculations by: (1) auditing actual sales; (2) confirming the SBA rate and sales used to set base rates; and (3) verifying the Company's method for calculating the SBA was consistent with the Commission's prior orders. Staff believes the Company calculated the SBA adjustment consistently with past Commission orders, and that the adjustment is reasonably accurate in calculating over-recovery of NPSE due to increased sales.
9. *Qualifying Facility/PURPA Expense*. For the April 2016 through March 2017 PCA period, the actual Idaho Jurisdictional PURPA expense is $147,780,952. The Idaho Jurisdictional PURPA expense included in base rates is $127,161,176. In this year's PCA deferral balance, the actual Idaho jurisdictional PURPA expense exceeded the PURPA expense included in base rates by $20,619,776. PURPA contracts are not subject to sharing, but they are subject to jurisdictional allocation. Staff audited the

actual monthly PURPA expense during the deferral period and believes the amount reported is accurate.

10. *Demand Response Incentive Payments*. Staff reviewed the Company's actual Demand Response Incentive payments included in the PCA deferral balance. Staff confirms there were $7,059,424 in actual DR Incentive expenditures in the current PCA deferral, which is $4,192,841 less than the $11,252,265 included in Base NPSE. Demand Response Incentive payments are allocated 100% to Idaho and are not subject to sharing. The prudency of the DR incentive payments will be determined in Idaho Power's annual DSM prudency filing currently before the Commission (Case No. IPC-E-17-03). Any disallowance as a result of that case will be reflected in next year's PCA deferral balance. This reduced level of DR incentive payments reduces the deferral balance to be recovered from customers.
11. *Revenue from the PCA Forecast*. The previous year's PCA forecast rates generated $45,487,126 in revenue. The forecast rate changes each June when the new PCA rates are established. Therefore, the deferral period reflects the rate set in the two previous PCA periods. This amount is credited to customers in the calculation of the overall deferral balance for the April 2016 through March 2017 deferral period. Staff verified the revenue collected during the PCA period.
12. Interest on the Deferral Balance. The deferral balance accrues interest at the customer deposit rate, currently 1%. The interest accrued during the current deferral period is $207,079. Staff verified the interest calculations and agrees with the Company.

Reconciliation of the True-up Analysis

As discussed earlier, the reconciliation of the true-up amount is the difference between what was approved to be collected or refunded when the PCA rate for the previous year was set, and what was actually collected or refunded. The reconciliation of the true-up assures that the amount approved for recovery is the amount actually recovered. Table 6, below, summarizes the reconciliation of the true-up for the 2016-2017 PCA period. The $2,257,651 ending balance amount is the revenue requirement used to form the reconciliation of the true-up portion of the overall PCA rate.

Staff audited the amounts booked to the reconciliation of the true-up, verified the Company's calculations, and reviewed the method used to ensure it complies with past Commission orders. As a result of its review, Staff believes the Company correctly reconciled the true-up. The specifics of Staff's review are discussed below.

Table 6: True-Up Reconciliation

2015-2016 True-Up Deferral (Order No. 33526)	$ 43,661,193
2015-2016 True-Up of the True-Up Ending Balance	(5,073,137)
Revenue Sharing (Order No. 33526)	(3,171,340)
DSM Rider Funds (Order 33526)	(3,970,036)
Net Amount Set for Recovery/(Refund)	31,446,680
Collections from True-Up Rates	(29,381,911)
Interest	192,882
Subtotal	(29,189,029)
True-Up Reconciliation	$2,257,651

1. 2015-2016 Forecast True-up Balance. The ending true-up deferral balance from the April 2015 through March 2016 PCA period was approved in Order No. 33526; Case No. IPC-E-16-08. The ending deferral balance in last year's PCA was $43,661,193. This amount is added to the beginning balance of the reconciliation of the true-up, with recovery set to start in June 2017 when new PCA rates are implemented. This amount has been properly recorded in the month of April 2016 in the reconciliation of the true-up for recovery.
2. 2015-2016 Reconciliation of the True-Up Balance. The remaining balance in the reconciliation of the true-up that was under-recovered in the previous PCA period is the beginning balance of the reconciliation of the true-up for this PCA period. The amount of $5,073,137 was over-recovered in the previous period, and has been properly recorded in the reconciliation of the true-up as the beginning balance.
3. Revenue Sharing. The Revenue Sharing benefit of $3,171,340 was approved in the previous PCA, Order No. 33526, Case No. IPC-E-16-08. Staff has verified that this Revenue Sharing amount is properly reflected in the reconciliation of the true-up.

4. DSM Rider Funds. The DSM Rider Transfer was approved in Order No. 33000 and current DSM Rider rates approved in Order No. 33526. The $3,970,036 amount on Line 104 of Company Exhibit No. 1 represents the collections of the DSM Rider portion of current Schedule 55 rates over the 2015-2016 PCA period. Staff has verified that the reconciliation of the true-up properly reflects this amount. Order No. 33736 eliminated this annual transfer of DSM Rider funds to the PCA, however this amount from previous PCA is included in the reconciliation of the true-up.
5. Collections from True-Up Rates and Interest. Staff reviewed and verified the collections from customers and the interest calculations. Staff has also verified that the collections and interest are properly reflected in the reconciliation of the true-up.

Revenue Sharing

The Commission established a mechanism in 2010 that required the Company to share revenue with customers based on the Company's actual Idaho jurisdictional year-end ROE. *See* Order No. 30978. The Commission subsequently modified the Revenue-Sharing mechanism and extended it in Order Nos. 32424 and 33149. The terms are currently effective through 2019, or until otherwise modified or terminated by Commission Order, or the full $45 million of Accumulated Deferred Investment Tax Credits (ADITC) are amortized.

The Company's 2016 year-end Idaho jurisdictional ROE was 9.53%. Since the ROE was between 9.5% and 10%, there is no revenue sharing for 2016. Staff has reviewed the work papers, source documents, and supporting documentation and agrees with the Revenue Sharing calculations.

DSM Rider

In Case No. IPC-E-16-33, Idaho Power filed an Application requesting that the Commission approve a decrease in the Energy Efficiency Rider rate, and a $13 million refund of previously collected Rider funds to be included in the 2017/2018 PCA mechanism, and the elimination of the annual transfer of $4 million of Rider funds through the PCA. In Order No. 33736, the Commission found it fair just and reasonable to refund $13 million of previously collected Rider funds to customers, and to eliminate the annual transfer of $4 million of Rider funds through the PCA. In this Application, the Company has excluded the annual $4 million

Rider transfer through PCA. The Company has also included the $13 million refund of previously collected Rider funds in this PCA filing.

Rate Calculations

Staff thoroughly reviewed the components that make up this year's Schedule 55 PCA rates and have concluded that they are fair, just, and reasonable. Staff's review of the rates for the traditional PCA components and of the DSM Rider refund included verification that: (1) the rates were calculated accurately; (2) the methods used to spread the rates across the customer classes provided a fair allocation; and (3) the methods complied with past Commission orders. Included is a copy of the combined PCA rate for both the traditional PCA and the DSM Rider refund for each customer class as Attachment C to these Comments.

As noted previously, the Company calculated the overall PCA rate of 0.7361 ¢/kWh by summing the rates of the three traditional components: the forecast, the true-up, and the reconciliation of the true-up. Staff confirmed that the method used to allocate the revenue requirement across the customer classes was done on an equal cents per kilowatt-hour basis. This ensures that customers share the PCA revenue requirement based on the amount of energy consumed which is how NPSE is allocated in customer base rates.

The only other additional rate component in this year's PCA is the DSM Rider refund. The Company allocated the $13 million refund using each class's proportional share of forecasted base revenues for the 2017-2018 PCA collection period. Staff agrees with the Company that this method approximates the proportion of the initial DSM Rider collected from each class and that the refund is allocated back to customers in approximately the same way.

CUSTOMER NOTICE AND PRESS RELEASE

The Company's press release and customer notice were included with its Application. Staff reviewed the documents and determined that both meet the requirements of Rule 125 of the Commission's Rules of Procedure (IDAPA 31.01.01).

The notice was included with customer bills. Customers who would receive their bill (with the enclosed notice) toward the end of the processing time for this case were also sent a postcard by direct mail. All customers will be mailed a notice (by bill insert or postcard) no later than May 19, 2017, which will allow some but not all customers a reasonable opportunity to file timely comments with the Commission by the May 12, 2017 deadline. Staff recommends that the Commission accept late-filed comments, recognizing the probability that the Commission will be unable to take into consideration comments filed by customers whose bills are issued at the end of the billing cycle. As of May 11, 2017, the Commission had received one comment that is opposed to the proposed increase.

RECOMMENDATIONS

Staff recommends the following:

1. The Commission approve a total deferral amount of $33,953,028 ($33,745,950 without interest) for recovery through Schedule 55 rates as shown in Staff Attachment C, effective June 1, 2017.
2. The Commission accept late filed customer comments.
3. The Company to provide a copy of all reports analyzing the root cause of failures and downtime that occurred at the Langley Gulch facility during the October through December 2016 timeframe.

Respectfully submitted this 12th day of May 2017.

Brandon Karpen
Deputy Attorney General

Technical Staff: Daniel Klein
Kathy Stockton
Rachelle Farnsworth
Mike Louis
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Idaho Power Company
Calculation of Revenue Impact 2017 - 2018
State of Idaho
Power Cost Adjustment
Filed April 14, 2017

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers [1]	Normalized Energy (kWh) [1]	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	435,475	5,015,915,934	$510,024,382	101.68	$2,959,590	$512,983,972	102.27	0.58%
2	Master Metered Mobile Home Park	3	22	4,160,204	$406,322	97.67	$2,614	$408,936	98.30	0.64%
3	Residential Service Energy Watch	4	0	0	$0	0.00	$0	$0	0.00	N/A
4	Residential Service Time-of-Day	5	1,284	22,594,745	$2,223,918	98.43	$14,030	$2,237,948	99.05	0.63%
5	Small General Service	7	27,849	126,287,341	$16,155,568	127.93	$44,256	$16,199,823	128.28	0.27%
6	Large General Service	9	35,111	3,766,683,562	$274,039,212	72.75	$3,071,752	$277,110,964	73.57	1.12%
7	Dusk to Dawn Lighting	15	0	6,409,145	$1,291,747	201.55	($2,673)	$1,289,074	201.13	(0.21)%
8	Large Power Service	19	112	2,206,538,543	$127,815,650	57.93	$2,114,745	$129,930,395	58.88	1.65%
9	Agricultural Irrigation Service	24	18,275	1,868,682,807	$149,079,717	79.78	$1,399,127	$150,478,844	80.53	0.94%
10	Unmetered General Service	40	1,366	11,298,003	$983,979	87.09	$7,661	$991,641	87.77	0.78%
11	Street Lighting	41	1,827	26,828,367	$3,605,901	134.41	$5,764	$3,611,665	134.62	0.16%
12	Traffic Control Lighting	42	575	2,735,472	$173,305	63.35	$2,479	$175,784	64.26	1.43%
13	Total Uniform Tariffs		521,896	13,058,134,123	$1,085,799,702	83.15	$9,619,345	$1,095,419,047	83.89	0.89%
14	Special Contracts:									
15	Micron	26	1	549,560,120	$28,313,818	51.52	$551,853	$28,865,671	52.53	1.95%
16	J R Simplot	29	1	192,745,251	$9,368,898	48.61	$202,470	$9,571,369	49.66	2.16%
17	DOE	30	1	209,846,587	$10,573,901	50.39	$214,947	$10,788,847	51.41	2.03%
19	Total Special Contracts		3	952,151,958	$48,256,616	50.68	$969,270	$49,225,887	51.70	2.01%
20	**Total Idaho Retail Sales**		**521,899**	**14,010,286,081**	**$1,134,056,319**	**80.94**	**$10,588,615**	**$1,144,644,933**	**81.70**	**0.93%**

Notes:
[1] June 1, 2017 - May 31, 2018 Forecasted Test Year

Attachment A
Case No. IPC-E-17-06
Staff Comments
05/12/17

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	**Power Cost Adjustment**																
2	**April 2016 thru March 2017**																
3					April	May	June	July	August	September	October	November	December	January	February	March	Totals
4	**PCA Forecasted Revenues**	*Prior*	*New (Effective 6/1/16)*														
5	Actual Idaho Jurisdictional Billing Month Sales			Mwh	921,310	956,785	1,166,035	1,482,037	1,500,343	1,334,789	949,502	896,063	1,041,749	1,284,458	1,212,895	1,022,520	13,768,486
6	% of Prior Period Billings at Old Rate				100.000%	100.000%	63.679%	0.024%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
7	% of Current Period Billings at New Rate				0.000%	0.000%	36.321%	99.976%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
8	**Forecasted Billing Month Revenues**	$ 2.815	$ 3.422	$	(2,593,487.09)	(2,693,351.12)	(3,518,224.75)	(5,054,847.98)	(5,134,172.72)	(4,567,647.39)	(3,249,195.02)	(3,066,327.92)	(3,564,864.92)	(4,395,416.20)	(4,150,528.27)	(3,499,063.03)	(45,487,126.41)
9																	
10	**Sales Based Adjustment**	*Prior*	*New (Effective 6/1/15)*														
11	Actual Idaho Jurisdictional Billing Month Sales			Mwh	921,310	956,785	1,166,035	1,482,037	1,500,343	1,334,789	949,502	896,063	1,041,749	1,284,458	1,212,895	1,022,520	13,768,486
12	Normalized Idaho Jurisdictional Billing Month Sales			Mwh	947,192	953,286	1,131,686	1,370,142	1,428,766	1,300,608	1,045,495	957,864	1,081,014	1,177,663	1,101,149	1,004,027	13,498,892
13	Sales Change			Mwh	(25,882)	3,499	34,349	111,895	71,577	34,181	(95,993)	(61,801)	(39,265)	106,795	111,746	18,493	269,594
14	% of Prior Period Billings at Old Rate				0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
15	% of Current Period Billings at New Rate				100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
16	Sales Adjustment Prior To Sharing		$ 26.72	$	691,567.04	(93,493.28)	(917,805.28)	(2,989,834.40)	(1,912,537.44)	(913,316.32)	2,564,932.96	1,651,322.72	1,049,160.80	(2,853,562.40)	(2,985,853.12)	(494,132.96)	(7,203,551.68)
17	Sharing Percentage				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
18	**Sales Based Adjustment**			$	656,988.69	(88,818.62)	(871,915.02)	(2,840,342.68)	(1,816,910.57)	(867,650.50)	2,436,686.31	1,568,756.58	996,702.76	(2,710,884.28)	(2,836,560.46)	(469,426.31)	(6,843,374.10)
19																	
20	**Actual Non-QF**																
21	Fuel Expense-Coal			$	4,168,490.22	6,353,030.75	12,762,074.23	18,331,288.54	20,010,203.95	18,309,046.82	9,886,574.71	10,096,968.65	14,105,805.40	12,139,904.60	8,669,667.97	7,046,818.06	141,879,873.90
22	Fuel Expense-Gas			$	665,869.55	1,812,399.94	4,113,720.26	6,262,473.96	6,720,485.99	4,198,716.66	1,268,584.04	1,150,887.79	3,231,097.19	4,920,129.16	3,022,758.69	453,395.23	37,820,518.46
23	Non-Firm Purchases			$	3,334,793.60	3,072,570.90	4,869,567.25	9,283,438.55	7,842,434.84	4,468,274.48	6,569,174.54	9,338,951.08	14,171,137.87	6,701,493.38	4,778,704.95	4,579,120.74	79,009,662.18
24	Third Party Transmission			$	338,636.40	339,572.18	427,708.14	580,209.87	1,113,410.30	573,626.31	527,528.20	488,188.99	253,196.82	271,732.58	290,350.05	318,598.18	5,522,758.02
25	Surplus Sales			$	(432,333.00)	(439,068.42)	(83,790.51)	(1,469,058.52)	(1,577,271.46)	(2,718,101.88)	(2,646,653.14)	(2,307,748.63)	(3,496,027.16)	(669,275.09)	(4,270,571.00)	(5,658,378.26)	(25,768,277.07)
26	Water for Power (Leases)			$	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Total Actual Non-QF			$	8,075,456.77	11,138,505.35	22,089,279.37	32,988,352.40	34,109,263.62	24,831,562.39	15,605,208.35	18,767,247.88	28,265,210.12	23,363,984.63	12,490,910.66	6,739,553.95	238,464,535.49
28	Idaho Allocation				95.0%	95.2%	95.3%	95.8%	95.8%	95.4%	95.3%	94.6%	94.9%	94.8%	95.4%	95.2%	
29	Net Idaho Jurisdictional Actual Non-QF			$	7,671,683.93	10,603,857.09	21,051,083.24	31,602,841.60	32,676,674.55	23,689,310.52	14,871,763.56	17,753,816.49	26,823,684.40	22,149,057.43	11,916,328.77	6,416,055.36	227,226,156.94
30																	
31	**Base Non-QF**																
32	Fuel Expense-Coal			$	7,525,242.00	7,487,643.00	9,019,153.00	11,385,255.00	12,185,412.00	10,796,845.00	7,781,442.00	7,302,324.00	8,455,019.00	9,553,773.00	8,912,994.00	8,098,078.00	108,503,180.00
33	Fuel Expense-Gas			$	2,314,209.00	2,302,646.00	2,773,625.00	3,501,263.00	3,747,333.00	3,320,312.00	2,392,997.00	2,245,656.00	2,600,139.00	2,938,035.00	2,740,979.00	2,490,369.00	33,367,563.00
34	Non-Firm Purchases			$	4,342,083.00	4,320,388.00	5,204,073.00	6,569,319.00	7,031,012.00	6,229,805.00	4,489,910.00	4,213,459.00	4,878,566.00	5,512,549.00	5,142,819.00	4,672,610.00	62,606,593.00
35	Third Party Transmission			$	378,398.00	376,507.00	453,517.00	572,494.00	612,729.00	542,907.00	391,281.00	367,189.00	425,151.00	480,400.00	448,179.00	407,203.00	5,455,955.00
36	Surplus Sales			$	(3,588,093.00)	(3,570,166.00)	(4,300,402.00)	(5,428,577.00)	(5,810,099.00)	(5,148,019.00)	(3,710,251.00)	(3,481,805.00)	(4,031,418.00)	(4,555,312.00)	(4,249,784.00)	(3,861,227.00)	(51,735,153.00)
37	Water for Power (Leases)			$	165,106.00	164,281.00	197,883.00	249,796.00	267,352.00	236,886.00	170,727.00	160,216.00	185,506.00	209,613.00	195,555.00	177,676.00	2,380,597.00
38	Net 95% Items			$	11,136,945.00	11,081,299.00	13,347,849.00	16,849,550.00	18,033,739.00	15,978,736.00	11,516,106.00	10,807,039.00	12,512,963.00	14,139,058.00	13,190,742.00	11,984,709.00	160,578,735.00
39	Idaho Allocation				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
40	Net Idaho Jurisdiction 95% Items			$	10,580,097.75	10,527,234.05	12,680,456.55	16,007,072.50	17,132,052.05	15,179,799.20	10,940,300.70	10,266,687.05	11,887,314.85	13,432,105.10	12,531,204.90	11,385,473.55	152,549,798.25
41																	
42	**Idaho Jurisdiction Change From Base**			$	(2,908,413.82)	76,623.04	8,370,626.69	15,595,769.10	15,544,622.50	8,509,511.32	3,931,462.86	7,487,129.44	14,936,369.55	8,716,952.33	(614,876.13)	(4,969,418.19)	74,676,358.69
43	Sharing Percentage				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
44	**Net Power Supply Costs Deferral**			$	(2,762,993.13)	72,791.89	7,952,095.36	14,815,980.65	14,767,391.38	8,084,035.75	3,734,889.72	7,112,772.97	14,189,551.07	8,281,104.71	(584,132.32)	(4,720,947.28)	70,942,540.77
45																	
46	**Emission Allowance and REC Sales**																
47	Emission Allowance Sales Credit			$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	Renewable Energy Credit Sales			$	(370,306.14)	(59,205.57)	2,750.18	258.91	(97,303.15)	(25,890.02)	(1,014.26)	3,567.15	167.90	(852,270.87)	0.00	(34,130.19)	(1,433,376.06)
49	Total Emission Allowances and REC Sales			$	(370,306.14)	(59,205.57)	2,750.18	258.91	(97,303.15)	(25,890.02)	(1,014.26)	3,567.15	167.90	(852,270.87)	0.00	(34,130.19)	(1,433,376.06)
50	Idaho Allocation				95.0%	95.2%	95.3%	95.8%	95.8%	95.4%	95.3%	94.6%	94.9%	94.8%	95.4%	95.2%	
51	Sharing Percentage				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
52	**Net Emission Allowances and REC Sales**			$	(334,201.29)	(53,545.52)	2,489.88	235.63	(88,555.60)	(23,464.13)	(918.26)	3,205.79	151.37	(767,555.15)	0.00	(30,867.34)	(1,293,024.62)
53																	
54	**Demand Response Incentive Payments**																
55	Actual			$	0.00	0.00	180,683.88	2,743,287.14	3,321,880.33	812,691.72	876.44	0.00	0.00	4.17	0.00	0.00	7,059,423.68
56	Base			$	780,401.00	776,502.00	935,327.00	1,180,702.00	1,263,682.00	1,119,681.00	806,970.00	757,284.00	876,823.00	990,769.00	924,317.00	839,807.00	11,252,265.00
57	**Change From Base**			$	(780,401.00)	(776,502.00)	(754,643.12)	1,562,585.14	2,058,198.33	(306,989.28)	(806,093.56)	(757,284.00)	(876,823.00)	(990,764.83)	(924,317.00)	(839,807.00)	(4,192,841.32)
58	Idaho Allocation				100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
59	Sharing Percentage				100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
60	**Demand Response Incentive Payment Deferral**			$	(780,401.00)	(776,502.00)	(754,643.12)	1,562,585.14	2,058,198.33	(306,989.28)	(806,093.56)	(757,284.00)	(876,823.00)	(990,764.83)	(924,317.00)	(839,807.00)	(4,192,841.32)
61																	
62	**Actual QF**																
63	Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages)			$	10,723,445.46	10,843,441.68	13,981,076.53	15,630,647.96	15,228,526.81	12,850,002.06	12,404,240.80	15,890,873.63	15,444,993.42	10,331,326.38	11,772,167.98	10,072,177.19	155,172,919.90
64	Idaho Allocation				95.0%	95.2%	95.3%	95.8%	95.8%	95.4%	95.3%	94.6%	94.9%	94.8%	95.4%	95.2%	
65	Idaho Jurisdictional Actual QF			$	10,187,273.19	10,322,956.48	13,323,965.93	14,974,160.75	14,588,928.68	12,258,901.97	11,821,241.48	15,032,766.45	14,657,298.76	9,794,097.41	11,230,648.25	9,588,712.68	147,780,952.03
66																	
67	**Base QF**			$	9,283,440.00	9,237,057.00	11,126,388.00	14,045,307.00	15,032,413.00	13,319,420.00	9,599,498.00	9,008,440.00	10,430,450.00	11,785,917.00	10,995,427.00	9,990,113.00	133,853,870.00
68	Idaho Allocation				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
69	Idaho Jurisdictional Base			$	8,819,268.00	8,775,204.15	10,570,068.60	13,343,041.65	14,280,792.35	12,653,449.00	9,119,523.10	8,558,018.00	9,908,927.50	11,196,621.15	10,445,655.65	9,490,607.35	127,161,176.50
70																	
71	**Idaho Jurisdiction Change From Base**			$	1,368,005.19	1,547,752.33	2,753,897.33	1,631,119.10	308,136.33	(394,547.03)	2,701,718.38	6,474,748.45	4,748,371.26	(1,402,523.74)	784,992.60	98,105.33	20,619,775.53
72	Sharing Percentage				100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
73	**QF Deferral**			$	1,368,005.19	1,547,752.33	2,753,897.33	1,631,119.10	308,136.33	(394,547.03)	2,701,718.38	6,474,748.45	4,748,371.26	(1,402,523.74)	784,992.60	98,105.33	20,619,775.53
74																	
75																	
76	Total Deferral			$	(4,446,088.63)	(1,991,673.04)	5,563,699.68	10,114,729.86	10,094,087.15	1,923,737.42	4,817,087.57	11,335,871.87	15,493,088.54	(1,986,039.49)	(7,710,545.45)	(9,462,005.63)	33,745,949.85

Attachment B
Case No. IPC-E-17-06
Staff Comments
05/12/17

Idaho Power Company
Total PCA Rate Calculation
Class Allocated EE Rider Refund
State of Idaho
Sales Based Adjustment Rate Methodology

Line No	Tariff Description	Rate Sch. No.	(A) Allocated EE Rider Refund	(B) EE Rider Refund Dollars per kWh Rate	(C) PCA per kWh Rate	(D) EE Rider Refund + PCA Rate
	Uniform Tariff Rates:					
1	Residential Service	1	($5,758,844)	(0.001148)	$0.007361	$0.006213
2	Master Metered Mobile Home Park	3	($4,564)	(0.001097)	$0.007361	$0.006264
3	Residential Service Energy Watch	4	$0	0.000000	$0.007361	$0.007361
4	Residential Service Time-of-Day	5	($25,007)	(0.001107)	$0.007361	$0.006254
5	Small General Service	7	($184,762)	(0.001463)	$0.007361	$0.005898
6	Large General Service - Secondary	9S	($2,837,237)	(0.000864)	$0.007361	$0.006497
7	Large General Service - Primary	9P	($359,186)	(0.000750)	$0.007361	$0.006611
8	Large General Service - Transmission	9T	($2,908)	(0.000846)	$0.007361	$0.006515
9	Dusk to Dawn Lighting	15	($15,932)	(0.002486)	$0.007361	$0.004875
10	Large Power Service - Secondary	19S	($4,745)	(0.000746)	$0.007361	$0.006615
11	Large Power Service - Primary	19P	($1,433,307)	(0.000661)	$0.007361	$0.006700
12	Large Power Service - Transmission	19T	($20,443)	(0.000625)	$0.007361	$0.006736
13	Agricultural Irrigation Service	24	($1,754,014)	(0.000939)	$0.007361	$0.006422
14	Unmetered General Service	40	($11,655)	(0.001032)	$0.007361	$0.006329
15	Street Lighting	41	($43,800)	(0.001633)	$0.007361	$0.005728
16	Traffic Control Lighting	42	($1,997)	(0.000730)	$0.007361	$0.006631
17	Total Uniform Tariffs		($12,458,400)			
18	Special Contracts					
19	Micron	26	($318,418)	(0.000579)	$0.007361	$0.006782
20	J R Simplot	29	($104,589)	(0.000543)	$0.007361	$0.006818
21	DOE	30	($118,593)	(0.000565)	$0.007361	$0.006796
23	Total Special Contracts		($541,600)			
24	Total Idaho Retail Sales		($13,000,000)			

Note:
June 1, 2017 - May 31, 2018 Forecasted Test Year

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 12th DAY OF MAY 2017, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF** IN CASE NO. IPC-E-17-06, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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SECRETARY