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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO ESTABLISH A NEW BASE LEVEL OF NET POWER SUPPLY EXPENSE.	**CASE NO. IPC-E-13-20** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Idaho Power Company's application to set a new base level of net power supply expense ("NPSE").

BACKGROUND

On November 1, 2013, Idaho Power Company (the "Company") applied to the Commission for an Order authorizing the Company to increase its total system "base level" NPSE from $199,993,778 to $305,684,869.[1] *See* Attachment A. The Company would use the increased NPSE to: (1) update base rates on June 1, 2014; and (2) as the basis for quantifying 2014/2015 Power Cost Adjustment ("PCA") rates that also would take effect June 1, 2014. The Company says the proposed NPSE increase would be revenue neutral for all customer classes, and would not increase customers' bills. *See* Application at 1-2, 3, and 5.

[1] On November 4, 2013, the Company filed an Errata to Application that changed the proposed NPSE from $304,684,869 to $305,684,869. This Order refers collectively to the application and errata as the "Application."

The Company says it has filed this Application to correct future PCA rates, which the Company says will be artificially high because the Company's base rates currently recover less NPSE than the normalized base level NPSE. The PCA is a rate adjustment mechanism that allows the Company to recover from or return to customers the annual difference between actual NPSE and the normalized NPSE included in base rates, except for a sharing amount. The difference is collected from or returned to customers through a rate change each June 1. The base level NPSE consists of Federal Energy Regulatory Commission ("FERC") Accounts: 501, Fuel (Coal); 536, Water for Power; 547, Fuel (gas); 555, Purchased Power; 565, Transmission of Electricity by Others; and 447, Sales for Resale. Base NPSE has not been fully reevaluated and updated since 2010.

The Company proposes to increase base level NPSE to $305,684,869. The Company says it needs this increase because the NPSE recovery level in base rates is approximately $100 million below the current normal NPSE level. The Company currently recovers these ongoing, permanent costs through the PCA; but the PCA is designed to let the Company recover (or return) fluctuating, annual power cost differences rather than long-term, permanent costs. Therefore, the Company wants to switch recovery of these costs from the PCA to base rates. *Id.* at 3-4, citing Order No. 32821 (expressing concerns with using the PCA to recover long-term, ongoing costs).

The Company says the base level NPSE has increased since 2010 for three main reasons. First, the overall value of the Company's surplus power sales has decreased because lower market prices have limited the Company's ability to economically dispatch its thermal generating units. Second, the Hoku special contract ended in 2012, and the 2013 base level NPSE thus excludes Hoku revenue and load. Third, the Company's PURPA-related expenses have increased by 113% since 2010. *Id.* at 5.

The Company asks the Commission to approve the proposed, base-level NPSE increase by March 31, 2014. The Company says on April 15, 2014, it would apply to adjust the 2014/2015 PCA using the updated NPSE, and to increase base rates by the same amount, effective June 1, 2014. The Company explains that its proposal is "revenue neutral" because the base rate increase would generate the same revenue that the Company otherwise would have recovered through the PCA. *Id.* at 6.

Using the PCA's 95.53% energy-based jurisdictional allocation, Idaho's share of the $105.7 million difference in system-level base NPSE would be approximately $101 million.

Because the Company intends its proposal to be revenue neutral, it needs to adjust the $101 million difference to reflect the 95/5 customer-to-company PCA sharing that applies to a portion of the amount. The total allowed PCA recovery would be $99.3 million. The proposal thus would result in a $99.3 million base rate increase in Idaho jurisdictional base level NPSE after $1.7 million in PCA sharing is subtracted. The Company says the "PCA sharing adjustment" would continue to be reflected in base rates until the Company files its next general rate case or it otherwise is adjusted by the Commission. *Id.* at 7.

The Company proposes allocating the $99.3 million base rate increase using the PCA energy allocation method; that is, it would allocate the base rate increase to each customer class in proportion to the class's annual energy consumption. *See* Attachment A. Each class would thus contribute the same revenue to offset the NPSE as it would have contributed through the PCA. Base rate revenues would increase by $99.3 million while PCA revenues would decrease by $99.3 million. *Id.* at 7-8.

The Company also proposes to increase the Load Change Adjustment Rate ("LCAR") from $17.64 per megawatt-hour ("MWh") to $24.34 per MWh to reflect the change in base level NPSE collected through base rates. The LCAR change would take effect June 1, 2014. *Id.* at 8.

The Company recounts that the Commission previously ordered it to include transmission wheeling revenues along with transmission expenses in future PCA calculations. *Id.* at 8, citing Order No. 32821. The Company reiterates its view that the PCA should not include wheeling revenues, and says it would be improper to set a base level for the PCA's wheeling revenue component in this case. *Id.* at 8-10. In its Notice in this proceeding the Commission found "... that the transmission wheeling revenue issue is beyond the scope of this NPSE case." (p. 4).

STAFF ANALYSIS

Base Net Power Supply Expense

Base NPSE consists of amounts from the following accounts:

Account 501, Fuel Expense (coal)

Account 536, Water for Power

Account 547, Fuel Expense (gas)

Account 555, Purchased Power (non-PURPA)

Account 565 Third-party Transmission Expense

Account 442, Hoku First Block Revenue

Account 447, Surplus Sales Revenue

Account 555, Purchased Power (PURPA)

Account 555, Purchased Power (demand response incentives)

Fuel expenses, both for coal and gas, non-PURPA purchased power and surplus sales revenue are derived using the AURORA model. AURORA is an hourly dispatch model that simulates the operation of the WECC. The model satisfies forecasted loads by economically dispatching generation resources in light of transmission and resource operational constraints. AURORA tabulates the Company's costs to operate its resources and other costs and revenues associated with serving its loads. AURORA considers 85 historic annual water conditions and calculates annual system costs under each condition. The Company uses the average annual cost as the "normal" cost when establishing the system base NPSE.

AURORA-Derived Expenses

In reviewing the Company's AURORA results, Staff first examined the Company's changes to the model inputs since 2010 when base NPSE was last established. Some of the more significant changes are listed below. In summary, the Company:

- Implemented a new version of AURORA and an updated database that incorporates new generation resources and loads throughout the WECC;
- Added the new, 300 MW Langley Gulch plant to its resource portfolio;
- Added a new, non-PURPA power purchase agreement for the 22 MW Neal Hot Springs project;
- Added 490 MW of new PURPA resources to its portfolio;
- Updated heat rates, forced outage rates, plant capacities, O & M costs, and maintenance schedules for its thermal generation resources consistent with historic actuals;
- Updated its load forecasts, including removing load associated with Hoku;
- Modeled wind generation for PURPA facilities and the 101 MW Elkhorn project using hourly shapes instead of monthly blocks;
- Dispatched the Bridger, Valmy and Boardman coal plants based on a location within its service territory to better match true historic dispatch decisions;
- Updated coal fuel prices consistent with current supply contracts; and

- Updated gas fuel prices to reflect actual 2013 gas prices through September, with forecasted prices for the rest of 2013.

Staff agrees with all of the modeling changes and inputs adopted by the Company. Each change either improves AURORA's accuracy or is too insignificant to materially affect the results.

Effect of Gas Price on Net Power Supply Expense

Gas price is one of the biggest drivers of NPSE, second only to water conditions. Natural gas prices affect the Company's NPSE for several reasons. Most obviously, gas prices impact fuel costs for the Company's gas-fired generation units (Langley Gulch, Danskin, and Bennett Mountain). Gas prices also affect the cost of gas-fired generation throughout the WECC, thereby affecting market prices for electricity. Market prices for electricity are critical to the Company because it buys and sells in the market. High market prices increase the Company's cost to buy power. But more importantly, high market prices allow the Company to earn more when it sells surplus power. The reverse is true at lower gas prices. Because the Company sells much more energy than it buys, higher gas prices yield a benefit to the Company that is passed on to customers. Stated differently, higher electric market prices benefit the Company because it is a net seller in the higher-priced market. The benefit of high gas prices compounds because the Company's coal plants and generators like Langley Gulch are more often economic to operate at high gas prices; thus, the Company has more power to sell.

Because gas prices are critical to establishing NPSE but can be highly variable and difficult to predict, Staff analyzed a broad range of natural gas prices ranging from $2.50 to $6.00 per MMBtu.[2] The following graph depicts the results of Staff's analysis. Each major component of NPSE from AURORA is shown separately. The graph shows that changes in gas price significantly affect two primary NPSE components — coal-plant costs and market-sales revenue. The total cost for the Company's coal plants increases as gas prices increase because the coal plants are dispatched more. The revenue associated with market sales (shown as a negative expense in the graph below) increases as gas prices increase because market prices increase with gas price.

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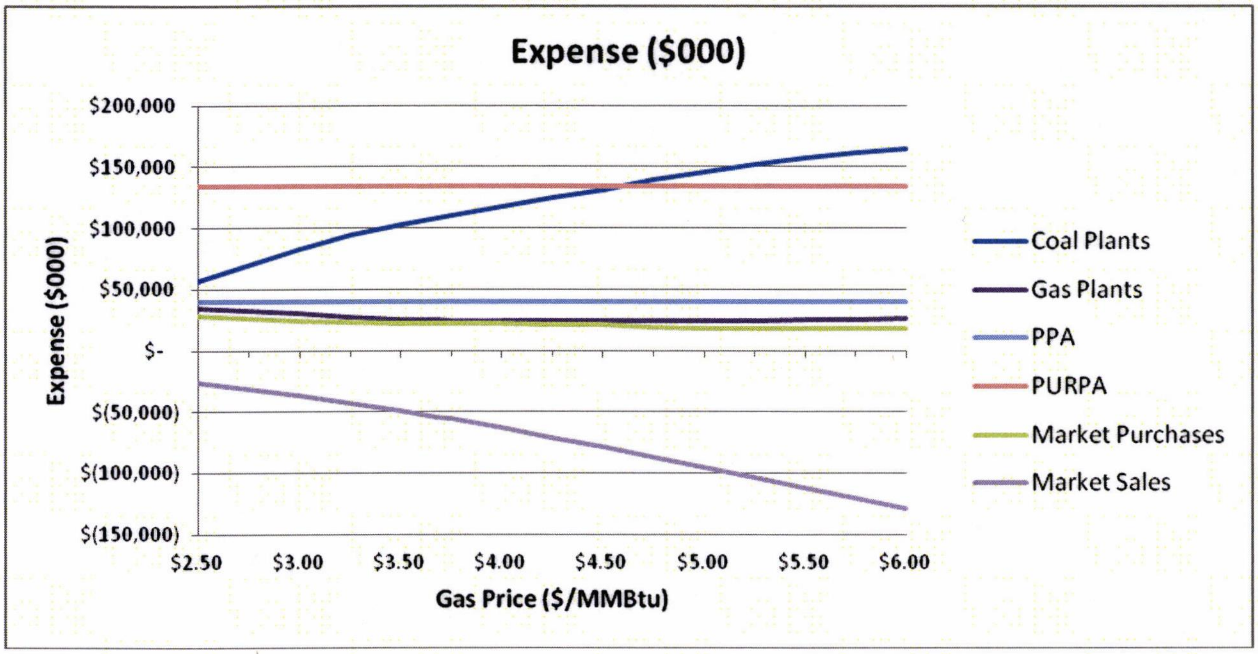
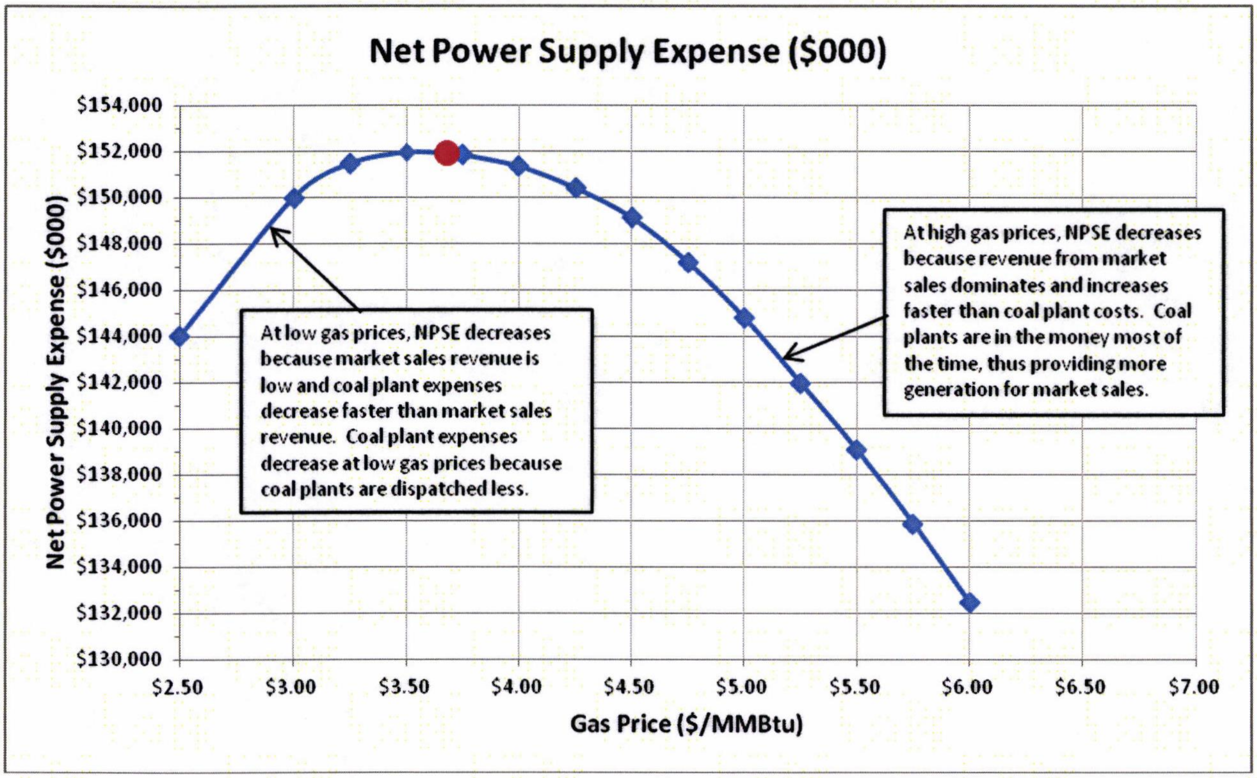
[2] Staff considered gas prices in southern Idaho near the Company's gas-fired plants. A basis differential (premium) to Henry Hub of $0.06 per MMBtu was maintained throughout Staff's analysis, consistent with the basis differential assumed by the Company.



Adding the NPSE components produces the results shown below. NPSE is highest at gas prices close to $3.50 per MMBtu, and decreases at either higher or lower gas prices. At low gas prices, NPSE decreases because market sales revenue is low and coal-plant costs decrease faster than market sales revenue. Coal-plant costs decrease at low gas prices because coal plants are dispatched less. At high gas prices, NPSE decreases because revenue from market sales increases faster than coal-plant costs. Coal plants are usually in-the-money and provide more generation for market sales. The large dot near the peak of the following graph marks the Company's proposed gas price and NPSE.



The current era of very low natural gas prices has created an interesting phenomenon that the Company probably has not experienced before. Now, any significant change in gas price, either up or down, decreases the NPSE. In the past, with gas prices much higher than they are now, an increase in gas price always decreased the NPSE.

When Idaho Power filed this case, average annual gas prices for 2013 were estimated to be $3.68 per MMBtu for southern Idaho. Since the Company's filing, wholesale gas prices have increased sharply due to exceptionally cold weather throughout the country. Forecasts of future annual prices, however, remain close to earlier estimates. Because future gas prices are not expected to differ substantially from the estimates in the Company's analysis, and because minor changes in gas price will have only minimal impact on the Company's NPSE, Staff accepts the gas price assumption in the Company's analysis.

Effect of PURPA Wind on NPSE

Much of the cost that the Company proposes to shift from the PCA to base rates is attributable to PURPA payments, and the vast majority of that amount is due to wind projects. As a result, Staff analyzed how PURPA wind projects impact the Company's portfolio.

Using AURORA, Staff determined that including PURPA wind projects in the Company's portfolio lowers NPSE by $33.9 million. But the Company pays about $85.5 million annually to buy power from PURPA wind projects. The net cost of PURPA wind to the Company is about $51.6 million. In other words, the Company could reduce its overall NPSE by about $51.6 million if it could buy an equal amount of energy from the market or produce that energy using its own resources.

Shifting PURPA costs from the PCA to base rates will relieve upward pressure on the PCA due to PURPA. But most PURPA contracts signed since about 2002 — the vast majority of which are wind contracts — include non-levelized rates. Non-levelized rates escalate during the life of the contract. Consequently, the amount shifted from the PCA to base rates will initially zero-out but then immediately resume growing as the non-levelized rates in the PURPA contracts escalate. Upward pressure on the PCA due to PURPA will resume even without new PURPA contracts. Therefore, shifting current PURPA costs from the PCA to base rates will provide only temporary relief.

Water for Power Expenses

"Water for Power" expense consists of the Company's payments for water stored in reservoirs that the Company uses to supplement generation at its hydroelectric generating facilities. The Company proposes to include $2.4 million for Water for Power expense in its NPSE. Water for Power expense has been maintained at $1.8 million in the last three NPSE Base Rate Filings.[3] This year's $2.4 million Water for Power expense is based on actual water-lease expenses from January 2012 through December 2012. The Company excluded 2013 actual expenses in computing the amount to be included in base NPSE due to poor water conditions and the lack of available 2013 water leases.

Staff reviewed the 2012 year-end balance for Account No. 536, Water for Power, as well as the actual expenses for 2012 recorded in the 2013 PCA true-up.[4] Staff also reviewed the 2013 actual expenses for water leases and agrees with the Company that the 2013 expenses should be

[3] See Final Orders 31042, 32426, and 32585 for NPSE filing for 2010-2012.
[4] See Case No IPC-E-13-10 Comments of the Commission Staff page 7 Final Order 32821.

excluded in computing a normalized amount. Staff thus agrees with the Company's proposal to include $2.4 million of Water for Power expenses in the base NPSE.

Purchased Power (Non-PURPA)

Non-PURPA purchased power consists of market energy purchases and power purchase agreements ("PPAs"). The Company proposes to include $62.6 million in purchased power costs in the base NPSE, up from $45.5 million in the 2012 base.[5] The cost of short-term market purchases is quantified within AURORA, and longer-term PPA costs are quantified outside of AURORA. Staff has reviewed the Company's reported expenses for 2013 and agrees with the Company's inclusion of $62.6 million as reasonable.

Third-Party Transmission Expenses

Transmission expenses consist of the Company's payments to other utilities for using their transmission systems to import power to serve the Company's native load customers and export power for surplus sales. The Company proposes to include $5.4 million in this year's NPSE base, down from the $8.2 million in the current base. The Company bases this amount on actual third-party transmission expenses for January 2013 through August 2013, forecasted amounts for September 2013 through December 2013, and estimates of purchased power and surplus sales. The Company averages its transmission estimate with the last six years of actual third-party transmission expense to provide a normalized value.[6]

Staff reviewed the Company's 2013 expenses and agrees that the Company's proposal to include $5.4 million of transmission expenses in the system base NPSE is reasonable.

Hoku First-Block Revenue

Pursuant to Order No. 32585, revenue associated with first-block energy sales to Hoku have been included as part of the existing NPSE. Because Hoku never started operating its plant and is now bankrupt, the Company proposes to remove $23.9 million in previously expected Hoku anticipated revenues from the NPSE.

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[5] See Final Order 32585.
[6] See Case No. IPC-E-13-20 Direct Testimony of Scott Wright page 12.

Staff agrees with the Company that the previously expected Hoku revenues should be removed from the NPSE. Staff has verified that anticipated Hoku-related load has appropriately been removed from the Company's AURORA modeling. Therefore, neither the costs nor the revenues associated with Hoku have been considered in computing the Company's proposed NPSE.

PURPA Expenses

PURPA expense consists of the Company's payments to owners of independent power projects for power under firm energy sales agreements. In accordance with PURPA, the Company must buy all energy offered for sale by the projects at contractual rates approved by the Commission. The Company proposes to include $133.9 million of system power supply costs in the base NPSE. The proposed amount includes $71.0 million paid in 2013 system costs that have not already been included in the base. Because this amount depends on 2013 costs, actual PURPA costs in later years may be more or less than the Company's proposed amount. When future amounts differ, deviations will be captured in future PCAs.

The Company proposes that the base NPSE include only PURPA expenses from existing projects. As future PURPA contracts are executed, payments associated with those new contracts will initially be captured in PCAs and eventually in base rates. As Staff previously discussed, the Company's total PURPA expenses will increase in the future even without new PURPA contracts as non-levelized rates escalate over the life of the existing contracts. Thus, shifting current PURPA costs from the PCA to base rates will only provide temporary relief, and both existing and new PURPA projects will continue to put upward pressure on rates.

Demand Response Incentive Payments

Demand response incentive payments consist of the Company's payments to participants in its Irrigation Peak Rewards, A/C Cool Credit, and Flex Peak demand response programs. The Company proposes to include $11.3 million of demand response incentive payments in the NPSE, which is the same amount that is currently in the NPSE and embedded in base rates. Staff has reviewed the amount the Company proposes to include and agrees that the amount should continue to be included in NPSE.

Base Rate Revenue Allocation and Rate Design

As previously discussed, Staff accepts a total system normalized base level of NPSE of $305,684,869. On a total system basis, this amount is $105,691,091 more than the amount last accepted for ratemaking purposes in Idaho. Based on this amount, Idaho customers will experience a $99,309,369 increase after jurisdictional allocation and PCA sharing. The amounts that make up this total are shown in Attachment A.

The example provided as Company Exhibit No. 2 demonstrates that the PCA revenue-allocation method and the allocation method proposed here (moving the increased NPSE into base rates) produce the same result. They produce the same result because the increase is allocated to customer classes on an equal ¢/kWh basis whether the increase is a base rate amount or a PCA amount. Staff thus agrees with the Company that moving additional normal NPSE into base rates is revenue neutral.

There has been some discussion that this case presents an opportunity to move customer classes toward cost-of-service. Staff disagrees and believes that a cost-of-service move in this case is inappropriate. A full cost-of-service case cannot be processed before the Company's mid-April PCA filing, or even before new rates take effect in June. The only cost-of-service information provided in this case shows how the proposed NPSE difference would flow to the customer classes in a cost-of-service study. (Idaho Power Company's Response to the First Production Request of the Industrial Customers of Idaho Power Request No. 1.) It ignores cost-of-service differences that exist due to amounts in all other accounts. Cost-of-service differences that existed in the Company's last general rate case (Case No. IPC-E-11-08) generally indicated high-load factor customer groups are paying less than they would at full cost-of-service. This was one reason Staff decided to settle that case with large amounts of normal PURPA costs not included in base rates. Staff recognized that the PCA would pick up these costs and allocate them to customers based entirely on energy. This result provided balance by allocating more costs to high-load factor customers to offset the fact that no other move was being made toward cost-of-service. Staff does not know what the results of a full cost-of-service study would be today. Staff believes any cost-of-service move at this point in time is inappropriate.

PCA Calculations

The Company also proposes to update the PCA base to include all normal NPSEs beginning June 2014. Staff agrees with the proposal. The PCA is designed to capture the difference between base and actual NPSE. In this specific case, the PCA sharing amount that is assigned to the Company is excluded from base rates but included in the PCA base. This is necessary to accomplish the revenue-neutral rate change the Company is proposing. It prevents the Company from recovering its PCA sharing amount associated with the proposed increase until that amount is allowed by the Commission.

Finally, the Company proposes to update the LCAR (i.e., the load change adjustment rate) from 17.64 $/MWh to 24.34 $/MWh. The LCAR is composed of a numerator that is measured in dollars and a denominator that is energy. The dollar amount in the numerator has two components: (1) the average NPSE embedded in base rates, and (2) the average energy classified fixed production cost embedded in base rates. When these amounts are divided by average load assumed in the ratemaking process, the resulting rate describes how the two amounts vary when load changes. The higher LCAR proposed in this case removes more costs from PCA deferral when loads grow to prevent over recovery of NPSE and fixed production costs. When loads decline the higher LCAR adds more dollars to the PCA deferral balance to compensate for under-recovered NPSE and some lost fixed production costs. In this filing, the Company proposes to update the LCAR numerator to include the proposed base level of NPSE. Staff supports the update. The PCA mechanism does not work as designed if the proposed change in NPSE is not tracked through to all of the affected PCA elements.

The Company correctly states that the base rate increase will offset the proposed June 1, 2014 PCA decrease. This does not mean that PCA rates will go to zero. There will be a 2013–2014 deferral balance that impacts PCA rates in June and a forecast of abnormal PCA amounts in the 2014–2015 PCA year that will also impact PCA amounts that go into rates on June 1, 2014. What the Company's proposal does mean is that PCA rates will be $99.3 million dollars less than they would be without its implementation.

STAFF RECOMMENDATIONS

Staff recommends that the Commission accept the Company's proposal to move normal NPSE that is now captured in each year's PCA filing into base rates. Staff further recommends that the full normal NPSE developed by Idaho Power be included in the PCA base and that the LCAR be set at 24.34 $/MWh. Staff agrees with the Company that these changes should take effect on June 1, 2014.

Respectfully submitted this 20th day of February 2014.

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Deputy Attorney General

Technical Staff: Keith Hessing
Rick Sterling
Sandra Walker

i:umisc/comments/ipce13.20kkkhsw comments

PCA REVENUE RECOVERY
Case No. IPC-E-13-20

Account	Description	2010 Base Currently Approved	2013 Base Proposed	Difference	Idaho Allocation	Customer's Share
					0.9553	0.95
501	Fuel (Coal)	167,192,744	108,503,180	(58,689,564)	(56,065,900)	(53,262,605)
536	Water For Power	1,828,640	2,380,597	551,957	527,282	500,918
547	Fuel (Gas)	51,934,201	33,367,563	(18,566,638)	(17,736,633)	(16,849,802)
555	Purchased Power (non-PURPA)	45,510,093	62,606,593	17,096,500	16,332,216	15,515,606
565	Third Party Transmission Expense	8,262,000	5,455,955	(2,806,045)	(2,680,603)	(2,546,573)
442	Hoku First Block	(23,921,466)	0	23,921,466	22,852,078	21,709,475
447	Surplus Sales Revenue	(124,916,153)	(51,735,153)	73,181,000	69,909,509	66,414,034
555	Purchased Power (PURPA)	62,851,454	133,853,869	71,002,415	67,828,316	67,828,316
555	Purchased Power (Demand Response)	11,252,265	11,252,265	0	0	0
	Total	199,993,778	305,684,869	105,691,091	100,966,266	99,309,369

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 20TH DAY OF FEBRUARY 2014, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-13-20, BY E-MAILING AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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