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, 2010 THROUGH MAY 31, 2011	))))))	**CASE NO. IPC-E-10-12** **ORDER NO. 31093**

On April 15, 2010, Idaho Power filed an Application to implement new Power Cost Adjustment (PCA) rates to be effective June 1, 2010 through May 31, 2011, and to change base rates. The Application states that the proposed PCA computation results from a Stipulation approved by the Commission in Order No. 30978, Case No. IPC-E-09-30 issued January 13, 2010. That Stipulation provides for a sharing between customers and Company shareholders of any PCA revenue reduction that results from this case. The Stipulation provides that PCA rates will be reduced by the full calculated amount and that base rates will be increased in an amount that partially offsets the PCA decrease. Idaho Power's filing calculates the PCA revenue reduction to be approximately $146.7 million and the base rate increase to be approximately $88.7 million. The net customer benefit is approximately $58 million which produces an average decrease in rates of 6.47%. PCA rate changes are spread on an equal cents-per-kWh basis, and thus not all customer classes experience the same percentage change.

IDAHO POWER COMPANY'S APPLICATION

The Power Cost Adjustment (PCA) Mechanism

In general, the PCA is a symmetrical annual rate adjustment mechanism that recovers abnormally high power supply costs from customers or credits customers with savings when power supply costs are abnormally low. The PCA has three components that combine to produce an annual rate. The first component is the forecast or a projection of the difference between normal power supply costs embedded in base rates and the coming year's power supply costs. The Company uses its Operating Plan to estimate the anticipated power supply costs. In this case, the Company calculates above-normal power supply costs of $87.6 million relative to power supply costs contained in current base rates. If base rates are increased as Idaho Power proposes, the projection is for above-normal power supply costs of $20.9 million relative to power supply costs contained in proposed base rates. After PCA sharing, these two amounts produce rates to recover forecasted above-normal power supply costs of 0.5814 cents per kWh and 0.1404 cents per kWh, respectively. The Company proposes to update base rates and use 0.1404 cents per kWh as the new PCA forecast rate component.

The second PCA component is the true-up. The true-up captures the difference between the previous year's projection and actual power supply costs. The true-up amount is converted to a rate by dividing by projected energy sales. Idaho Power calculates this amount to be $11,963,777 and the resulting rate to be 0.0888 cents per kWh.

The third PCA component is the reconciliation of the previous year's true-up. This component calculates the amount of the unrecovered true-up. The previous year's true-up amount is not precisely recovered because actual sales are different from the previous year's projected sales and because of a two-month lag between the end of the PCA accounting year and the implementation of new PCA rates. Idaho Power calculates the reconciliation of the true-up amount to be $11,284,407 and the resulting rate to be 0.0838 cents per kWh.

The combination of the three components produces a 2010-2011 PCA rate of 0.3130 cents per kWh (0.1404 + 0.0888 + 0.0838). The use of the lower projection rate of 0.1404 cents per kWh assumes that base rates are updated in this case to include a new level of normalized power supply costs.

The Stipulation approved by the Commission in Order No. 30978, Case No. IPC-E-09-30, also provides for a base rate increase to include, among other things, increases in normal power supply costs that have occurred since the Company's last general rate case. The Company's filing includes an increase in base rates of approximately $88.7 million. Case No. IPC-E-10-01, Order No. 31042, carried over to this case the issue of the appropriate level of Bridger coal costs to be included in base power supply costs and, therefore, in base rates. The amount of base level Bridger coal costs included in the Company's calculations of base power supply costs in this case is the level the Company proposed in the previous case.

The combined impact of the PCA rate decrease and the base rate increase proposed by the Company is shown on page 1 of Company Exhibit No. 2. The disparity in customer class rate change percentages results from the equal cents-per-kWh application of the PCA decrease. High load factor customers get larger percentage decreases when PCA rates are reduced just as they received larger percentage increases when PCA rates go up. PCA percentage increases and decreases are relatively small for smaller, generally lower load factor customers. In this case, two lighting classes, Schedule 15 – Dusk to Dawn Lighting and Schedule 41 – Street Lighting, are projected to receive net increases because their equal percentage base rate increase is greater than their equal cents-per-kWh decrease from the PCA.

STAFF AUDIT AND ANALYSIS

The PCA Forecast or Projection

Commission Staff reviewed the Company's Operating Plan-based Forecast and believes that it is reasonable. The Operating Plan incorporates the most current information available in each update.

The two parts of the forecast rate combine to produce the forecast rate shown of 0.1404 cents per kWh. Among other things, this rate reflects water conditions that are expected to be well below normal. Under this forecast methodology, Idaho Power does its own water forecast; but Staff verified that the Northwest River Forecast Center expects April through July Brownlee Reservoir inflow to be 52% of normal. Staff Comments, p. 4. Although this year's PCA rate is proposed to be substantially lower than last year's PCA rate, power supply costs are projected to be approximately $20 million above the normal level of power supply costs.

The PCA True-Up

Lines 4 through 78 of Exhibit No. 1 to Idaho Power witness Scott Wright's testimony shows the Company's calculation of the true-up deferral amount. To verify revenues and costs associated with Idaho Power's true-up deferrals, Staff conducted an audit of actual revenues and expenses that occurred during the PCA year. These revenues and costs included water lease expenses, fuel expenses for coal, fuel expenses for natural gas, power sales and purchases, third party transmission expenses, Hoku first block energy expenses, green tag sales credit (RECs), and qualifying facilities expenses. Staff also examined the emission allowance sales credit passed on to customers in the true-up of the true-up, and the risk management operating plan.

Staff identified the following items that are included in the PCA true-up:

1. <u>Water Leases</u>. 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 refund to customers. This year's PCA deferral balance includes actual water lease expenses of $2,205,906 and the amount included in base rates is $67,519, with the difference of $2,138,387 included in the deferral balance.

2. Fuel Expense – Coal. A large portion of Idaho Power's electricity comes from thermal power produced from coal plants. Idaho Power owns an interest in three coal plants, Bridger, Valmy and Boardman. The increase or decrease in the coal expense from base rates is included in the PCA. For the audit period of April 2009 to March 2010, the total coal expense for all plants in operation is $128,504,371. The total coal expense included in base rates is $133,454,723. This $4,950,352 reduction in coal costs from base costs is a benefit to customers and is subject to jurisdictional allocation and sharing.

3. Fuel Expense – Gas. Idaho Power currently owns and operates gas-fired combustion turbine generating plants at the Evander Andrews Power Complex (three Danskin units) and Bennett Mountain. These plants are both located near Mountain Home and account for 100% of gas usage.

For the audit period of April 2009 to March 2010, the total variable gas and gas transportation expense for both complexes was $18,420,326. The total gas and gas transportation expense included in base rates is $6,125,180. Accordingly, the additional gas expense that is included for future recovery from customers is $12,295,146 and is subject to jurisdictional allocation and sharing.

4. Power Sales and Purchases. Staff reviewed the power purchases and sales in conjunction with the Company's Risk Management Operating Plan. Staff states its analysis did not find any transaction that was not reasonable or that did not follow the Risk Management Committee's recommendations. Staff Comments, p. 6.

(a) Power Sales. During the PCA year ending March 31, 2010, the Company sold surplus power totaling $94,357,434, and the total surplus sales included in base rates is $116,568,567. The difference in the power sales from base rates is included in the PCA for recovery or refund and is subject to jurisdictional allocation and sharing. Actual surplus sales were less than base amounts by $22,221,133.

(b) Power Purchases. During the PCA year ending March 31, 2010, the Company made market purchases, excluding PURPA contracts, totaling $83,632,863. The total power purchases included in base rates is $57,231,921. Thus, actual purchased power costs exceed base amounts by $26,400,942.

5. Actual Qualifying Facilities Purchases Including Net Metering and Raft River. A qualifying facility (QF) is a generating facility that meets the requirements for QF status under

the Public Utility Regulatory Policies Act of 1978 (PURPA) and Part 292 of the Federal Energy Regulatory Commission's Regulations (18 C.F.R. Part 292). There are two types of QFs – cogeneration facilities and small power production facilities. Qualifying facilities are sometimes referred to as cogeneration/small power producers, or by the acronym CSPP.

For the audit period of April 2009 through March 2010, the actual QF expense is $64,344,768, and the QF expense included in base rates is $63,269,889. The difference in the QF expense from base rates is included in the PCA for recovery or refund. In this year's PCA deferral balance, the actual QF expense was more than the base QF by $1,074,879.

6. Third-Party Transmission. In Order No. 30715, Case No. IPC-E-08-19, the Commission concluded that third-party transmission costs that are incurred in conjunction with market purchases and sales should be tracked through the PCA like other variable power supply costs, and that including the expenses in the PCA is a straightforward treatment of power supply costs that fluctuate with power purchases and sales. For the audit period of April 2009 to March 2010, the actual third-party transmission expense is $6,692,114, and the third-party transmission expense included in base rates is $10,469,726. Thus, this year's PCA deferral balance includes this reduction in costs of $3,777,612 from those included in rates to the benefit of customers.

7. Hoku First Block Energy. In Order No. 31042, Case No. IPC-E-10-01, the Commission established the base level for net power supply for 2010, and in that Order, the Commission determined that the Hoku expenses should be captured in the PCA and not in base rates for 2010. Therefore, the actual costs are included in the PCA deferral, and there are not corresponding base level amounts of Hoku expenses. In this deferral balance, there is a credit of $611 included in the deferral balance.

8. Green Tag Sales Credit. In Order No. 30818, Case No. IPC-E-08-24, the Commission ordered that green tag sales benefits flow to customers, subject to jurisdictional allocations and sharing. The amount included in the deferral balance is $665,788. This is a benefit to customers.

This year's true-up calculation includes a negative load growth adjustment of approximately $23.7 million. Actual loads during the true-up year were below-normal loads in 10 of 12 months. The total below-normal load was 889,235 MWh, representing a 5.6% load decline. The adjustment in the true-up component is the product of the negative load growth and the load-growth adjustment rate (LGAR) of $26.63 per MWh. The LGAR 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 of production costs. When load declines the adjustment reimburses the company for lost fixed-production costs and makes the Company whole with respect to variable production costs. Staff Comments, p. 5. The result is that $21.3 million (after jurisdictional allocation and PCA sharing) was added to the deferral balance for recovery from customers in this year's PCA. Staff asserts that negative monthly load growth has previously been included in PCA calculations and is part of the approved calculation methodology. *Id.* Staff recommended no change to the load growth adjustment amounts or methodology in this case, but is currently reviewing the justification for the adjustment when load declines, and plans to meet with the Company to discuss possible modifications to load growth adjustment.

The Company-proposed true-up rate is 0.0888 cents per kWh and the Staff-proposed true-up rate is 0.0872 cents per kWh. Staff verified the Company's true-up deferral calculations, but recommended removal of an interest component from the calculation. In Case No. IPC-E-08-19, Order No. 30715, the Commission authorized Idaho Power to redistribute monthly base power supply costs in a specific manner to meet reporting needs of the Company. Staff contends the monthly redistribution was designed to leave annual base power supply costs unchanged, but the redistribution caused $215,027 of additional interest to be deferred. Staff Comments, p. 4. The difference in the Company's and Staff's true-up rate results from Staff's interest adjustment in the true-up component. Staff Comments, p. 9.

The PCA Reconciliation of the True-Up

The PCA reconciliation of the true-up amount is the difference between what was approved for collection or refund when the PCA rate for last year's true-up was set and the amount actually collected or refunded. The amount represents the under- or overrecovery of the true-up amount from the previous year because a different amount of kWh was sold than was anticipated in the rate design and because the true-up period included only 10 months with the true-up rate in place. The reconciliation of the true-up is a benefit to both the Company and customers because any true-up overcollection is returned to customers, and any true-up undercollection is recovered by the Company.

The Company included in this year's reconciliation of the true-up a benefit to customers from 2008-2009 SO2 emission sales. As directed in Order No. 30790, the Company recorded the proceeds from the sale of the 2008-2009 SO2 credits in the current year's PCA. The Idaho jurisdictional portion of the SO2 allowance proceeds, including interest but net of tax, was recorded in the PCA deferral account and included in the reconciliation of the true-up section in the months of April 2009 and June 2009. The total system SO2 amount is $5,229,875 plus accrued interest. The Idaho jurisdictional amount after jurisdictional allocation and sharing is $4,591,632. Staff Comments, p. 9.

Last year's unrecovered true-up amount to be recovered in this case is approximately $11.3 million, and the true-up of the true-up rate is calculated to be 0.0838 cents per kWh. Staff and the Company calculated the same rate for the reconciliation of the true-up. *Id.*

Staff's calculated PCA rate of 0.3114 cents per kWh is the sum of the three PCA components (0.1404 + 0.0872 + 0.0838 = 0.3114), and is well below the current PCA rate of 1.4022 cents per kWh. Staff Comments, p. 10.

Base Rates

Bridger Coal Costs

The Settlement Stipulation approved by the Commission in Case No. IPC-E-09-30, Order No. 30978, provided for an increase in base rates if PCA rates were reduced in this filing. The base rate increase includes an adjustment to normal power supply costs. Normal power supply costs were identified in Case No. IPC-E-10-01, Order No. 31042, as approximately $63.7 million more than are included in present base rates. Staff Comments, p. 10. The Commission did not fully resolve in Case No. IPC-E-10-01 the cost for Bridger coal that should be included in normal power supply costs.

Staff stated that the Bridger coal cost is an issue because the coal supply contract with Bridger Coal Company recently expired and coal costs under the new contract are significantly higher than under the old contract. Bridger Coal Company is a wholly owned subsidiary of Idaho Power Company and PacifiCorp, who also own the Jim Bridger power plant. When a regulated utility contracts with an unregulated affiliate, it is common practice to reflect in rates the lower of the actual cost or the comparable market cost. *Id.*

Staff reviewed the new contract, testimony and production requests in a case pending before the Oregon Commission, a white paper prepared by Idaho Power Company to address the issues (including the lower of cost or market issue), and responses to production requests asked by Staff and Intervenors and Idaho Power witness Tom Harvey's testimony in this case. Staff concluded that Idaho Power's proposal for Bridger coal costs appear logical, reasonable and consistent. Staff Comments, pp. 10-11. In addition, Bridger Coal Company profits flow to Idaho Power subsidiary IERCO and IERCO profits flow back to customers in Idaho Power Company general rate cases. Staff did not modify the Bridger coal costs proposed by the Company and included in base power supply costs in this filing, and thus supports an increase in normalized base power supply costs of $63.7 million.

Rates

The Company and Staff both proposed a substantial decrease in PCA rates of approximately $147 million. Under the Stipulation, a PCA reduction of this magnitude allows the Company to move $63.7 million (Case No. IPC-E-10-01, Order No. 31042) in increased normal power supply costs into base rates along with $25 million in other costs. The Stipulation further requires that the base rate increase be spread to customer classes and rate components within each customer class on an equal percentage of revenue basis, except for residential and small commercial customer charges, which are to remain unchanged. Staff reviewed the Company's base rate calculations and agrees that they are correct. Staff Comments, p. 11. With the base rate increase, Staff proposed a PCA decrease of $58.2 million, which averages 6.49% across all customer classes. The Schedule 1 residential class rate decrease is 3.24%.

Staff recommended that the Commission approve the base rate increases filed by the Company, and approve a PCA rate of 0.3114 cents per kWh for the June 1, 2010 through May 31, 2011 period. This PCA rate differs from the Company's proposal due to the true-up interest adjustment recommended in Staff comments.

OTHER COMMENTS

Magic Water Company; Idaho Irrigation Pumpers Association, Inc.; Industrial Customers of Idaho Power

Written comments were also filed by the Idaho Irrigation Pumpers Association, Inc. (Irrigators); the Industrial Customers of Idaho Power (ICIP); and the Magic Water Company, Inc. The Magic Water Company provides irrigation water to farmers in the Magic Valley region of southern Idaho. Magic Water objects to an increase in permanent rates, because it will remain in place. The PCA result this year is an overall reduction in rates for irrigation customers.

The Irrigators filed comments to protest an expense adjustment of $23,680,328 in the Company's PCA calculation. The adjustment occurs by application of the LGAR in the true-up component of the PCA, and reflects a decline in load growth during the year. The Irrigators object to the $23.7 million adjustment for what it describes as phantom expenses. Irrigators argue the LGAR was never intended to apply in years when load declines rather than increases. The Irrigators contend that, although the PCA is designed to be symmetrical, the LGAR was not. Irrigators Comments, p. 4. The LGAR "was designed to insure that there was no double recovery of the additional power supply expense due to load growth." *Id.* The Irrigators argue that "when the power supply expenses decrease because the load has dropped, the EARG/LGAR should never be increased to make up for expenses that were never incurred." *Id.*

The Irrigators argue that the application of the LGAR in this case is unjust and unreasonable because Idaho Power would collect revenue through the PCA for an expense it did not incur. The Irrigators recommend that the amount of $23.7 million be disallowed in the PCA, or in the alternative, that the Commission reserve the collection of the $23.7 million until after workshops are convened in an open docket, Case No. PAC-E-10-01, to address the appropriate application of the LGAR. Irrigators Comments, p. 10. The Irrigators also join in the comments made by the Industrial Customers regarding increased costs of coal used at the Bridger coal plant.

The Industrial Customers recommend that some coal costs associated with the Bridger plant be disallowed. Industrial Customers believe the Company's cost for coal associated with the Bridger plant exceed comparable market rates by over $16 million. The Industrial Customers note that Idaho Power and PacifiCorp jointly own the Bridger power plant, and obtain approximately one-third of the coal consumed by the plant from the Black Butte Coal Mine. The remainder of the coal to operate the Bridger plant is supplied by the Bridger Coal Company, an entity owned through Idaho Power and PacifiCorp affiliates. Industrial Customers Comments, p. 4. The Industrial Customers do not contend the coal transactions for the Bridger plant are "per se imprudent," but that "the affiliate relationship and associated profits warrant close scrutiny of the B[ridger] C[oal] C[ompany] sales price ratepayers will pay." Industrial Customers Comments, p. 6.

The Industrial Customers noted that the Commission did not fully resolve the amount of Bridger coal costs to include in Idaho Power's net power supply costs when the Company previously filed an application to establish those costs. Instead, the Commission stated: "We expect the Company in that [PCA] docket to support its proposed adjustment to the Bridger coal costs." Industrial Customers Comments, p. 6, *quoting* Order No. 31042, p. 8. Thus, the Industrial Customers assert, "the Company has the burden of proving in this case that the B[ridger] C[oal] C[ompany] sales price passed onto ratepayers is equal to or less than the sales price of a market alternative, and if it fails to do so the Commission may disallow the difference from the 2010 NPSE [net power supply expense]." Industrial Customers Comments, p. 7. The Industrial Customers contend Idaho Power did not meet this burden and thus request that the Commission disallow in the PCA net power supply expense "all or some portion of the B[ridger] C[oal] C[ompany] surface-mined coal costs that exceed the comparable market rate for surface-mined coal by over $16 million." Industrial Customers Comments, p. 19.

The Industrial Customers also argue against the cost adjustment resulting from application of the LGAR during a year that load declined. The Industrial Customers assert that "the use of a *load growth* mechanism in the face of *declining loads* is counterintuitive and yields unintended consequences." Industrial Customers Comments, p. 17. The Industrial Customers assert that although the LGAR "has logically been used to recognize declining loads within individual months of test year with an overall increase in load, it has never been used to increase rates in the same manner as decoupling" in a year with an annual decrease in load. Industrial Customers Comments, p. 18. Accordingly, the Industrial Customers recommend the Commission deny the LGAR adjustment in the PCA of $23.7 million or, "at the very least, the Commission should expressly state that any recovery from LGAR is subject to further reduction pending resolution of a further investigation of the issue." Industrial Customers Comments, p. 19.

Public Comments

As of May 17, 2010, two customers had submitted comments to the Commission regarding the PCA. One customer is in favor of the proposed reduction in the PCA charge, although the customer feels that the reduction should be larger. The other customer questions why the proposed PCA reduction is less for residential customers than the overall proposed decrease. The customer also feels that residential customers are subsidizing other classes of customers, all-electric residential customers are being unfairly penalized, and it is inappropriate to use rate schedules to force energy conservation.

Idaho Power Reply Comments

The Company filed reply comments on May 21, 2010, addressing the two issues discussed by the Industrial Customers and the Irrigators, as well as Staff's calculation of the interest adjustment. Regarding the cost of coal to operate the Bridger plant, the Company stated that the Industrial Customers' conclusion that Idaho Power has a financial disincentive to purchase coal for the Bridger plant from a third party, such as the Black Butte Coal Company, is incorrect. An Idaho Power subsidiary, Idaho Energy Resources Company (IERCO), has a fixed investment in plant and equipment at Bridger Coal Company. The sales price for Bridger Coal Company coal is adjusted based upon changes in mine operating costs and not changes in IERCO rate base. Idaho Power stated that the price for coal sold by Bridger Coal Company to the Bridger plant is periodically set at a level designed to achieve a targeted return on investment, as established in a general rate case. Idaho Power Reply Comments, p. 2. The Company states its goal is to optimize the surface and underground production levels from Bridger Coal Company along with purchases from Black Butte Coal to achieve long-term fuel supply strategy, rather than achieve an embedded profit incentive as asserted by the Industrial Customers. Finally, Idaho Power asserts that the sales price for Bridger Coal Company coal is adjusted based upon changes in mine operating costs rather than changes in IERCO rate base. *Id.*

The Company also responded to the Industrial Customers and Irrigators' argument regarding the use of the LGAR in years of declining load. The Company stated that in periods of load growth, "the LGAR eliminates the double recovery of power supply expenses and the potential for double recovery of other specific generation-related costs that may or may not be increasing." The Company asserts that in periods of load decline, "the LGAR is consistently applied to ensure that the Commission-allowed base level power supply costs are appropriately accounted for in the calculation of the PCA." Idaho Power Reply Comments, p. 5. The Company maintains that the LGAR must be reciprocal to prevent double counting in the PCA. The Company argues that the purpose of the LGAR "remains constant whether loads increase or decline – that is, to prevent double counting by adjusting actual power supply expenses to reflect actual comparable power supply costs at normal load levels." Idaho Power Reply Comments, p. 8.

Idaho Power also responded to Staff's adjustment of the interest expense in the true-up portion of the PCA relating to net power supply costs. The Company argues that its interest calculation is consistent with the Commission-approved method of PCA deferral reporting for base net power supply expenses. The Company asserts that Staff's proposed removal of $215,027 of interest is contrary to the accepted interest calculation methodology, and will require the Company to maintain two sets of books. Idaho Power Reply Comments, p. 9.

COMMISSION FINDINGS

Idaho Power's Application requests implementation of new PCA rates during June 1, 2010 through May 31, 2011, as well as increases to base rates, and asserts the Company-proposed rates are consistent with a Stipulation approved by the Commission in Case No. IPC-E-09-30. Challenges are made to three discrete components of the rate structures, but otherwise the record for the Commission's review is uncontested. The Commission Staff proposed an adjustment to an interest expense that is part of the true-up component of the PCA. The Industrial Customers and Irrigators recommend disallowance of an LGAR adjustment in the Company's recovery of costs during the past PCA year, which also affects the true-up component. Finally, the Industrial Customers and Irrigators challenge part of the cost of coal purchases used in determining base net power supply costs that comprises a majority of the increase in base rates. Because part of the PCA recovery each year relates to the normal net power supply costs that are recovered in base rates, determination of the base rates affects the PCA recovery of forecasted power supply costs.

Three separate components, each with its own rate calculation, are used to establish a final PCA rate for the coming year. The first component is based on a forecast or projection of power supply costs for the next PCA year (June 1 – May 31). After determining the anticipated power costs, a rate is calculated to recover those costs that exceed the amount that is recovered in base rates for normal power supply costs. The Company projected that power supply costs will exceed normalized power costs by $20.9 million, and calculated a rate of 0.1404 cents per kWh to recover the forecast power supply component of the PCA. That calculation is premised on an adjustment to base rates to increase the amount of normal power supply costs recovered in those rates. The Industrial Customers and Irrigators challenge Idaho Power's determination of normalized power supply costs, and the resulting increase proposed for base rates, but do not dispute the Company's calculation of the PCA rate component intended to recover projected power supply costs above the normalized costs. More specifically, the Industrial Customers and Irrigators dispute the cost of coal required to operate the Bridger plant. An increase in the Bridger coal cost is a significant part of the increase in the Company's net power supply expense.

The Stipulation approved by the Commission in Case No. IPC-E-09-30 stated that Idaho Power would file a separate case to establish the base level for Net Power Supply Expense (NPSE) to be used for both base rates and PCA calculations. The Company filed that application in Case No. IPC-E-10-01, and the Commission subsequently authorized "an increase of $63,701,694 in the Company's base level Net Power Supply Expense (NPSE) as a working number for the Company's 2010-2011 PCA filing, deferring final calculation of authorized NPSE to the PCA case." Order No. 31042, p. 9. The Commission recognized that Staff, Industrial Customers and Irrigators had not completed their analysis of the proposed increase in Bridger coal costs, and thus provided "the opportunity for further investigation and assessment in the context of the Company's 2010-2011 PCA docket." Order No. 31042, p. 8.

The Company proposed to include the $63.7 million increase for the updated net power supply expense in base rates in this case, and included prefiled testimony and exhibits to support that amount. Staff reviewed the information provided by the Company both in its Application and in discovery responses, and stated it had "not identified any justification to reject or modify the Bridger coal costs proposed by the Company and included in base power supply costs in this filing." Staff Comments, p. 11. The Industrial Customers and Irrigators do contest the Bridger coal costs, primarily with the argument that the Bridger costs exceed the cost of other coal that is available in the market.

The Commission has reviewed the information provided by the Company in this case, and the information, argument and analysis of coal costs presented by the Industrial Customers and Irrigators, and finds that Idaho Power has adequately met its burden to establish the reasonableness of the Bridger coal costs to be included in the base level power supply costs. The Bridger plant is located in the Green River Basin in Wyoming, and sits next to the Bridger coal mine. Idaho Power purchases approximately one-third of the necessary coal from Black Butte, a third-party mine operator, and verified that Black Butte "simply does not have enough volume available to replace the B[ridger] C[oal] C[ompany] surface production." Harvey Direct, p. 11. In addition, even if more Black Butte coal were available, the Company has no assurance it could be obtained at the same price as under the existing contract. *Id.* The Company also reviewed possible coal purchases from the Powder River Basin, approximately 566 miles from the Bridger plant, and concluded it would not be cost effective, particularly because "use of coal from the mines in the [Powder River Basin] would require significant capital investment in the Plant because of the different quality and make-up of the coal compared to the blend of BCC [Bridger Coal Company] and Black Butte coal the Plant currently burns." Harvey Direct, p. 12. In addition, because any profits obtained by BCC are passed on to Idaho Power's customers in rate cases, the usual concern about improper charges to customers in affiliate transactions is largely removed.

On the record presented, the Commission approves the amount of $63,701,694 increase in Idaho Power's net power supply costs to be included in base rates. There is no dispute to the Company's projection that power supply costs during the next PCA year will exceed normalized power costs by $20.9 million, or the Company's calculation of a rate of 0.1404 cents per kWh to recover the forecast power supply component of the PCA. The Commission thus approves a rate of 0.1404 cents per kWh for the forecast component of the PCA rate.

Another dispute to Idaho Power's proposed PCA rates is in the true-up piece of the PCA. The most significant challenge is to the effect of the LGAR in establishing the costs recovered in the PCA during the last year. Because load decreased in 10 of the 12 months during the year, application of the LGAR increased recoverable costs by $23.7 million, or 51% of the Company's request to recover approximately $41.9 million in above-normal costs. Staff Comments, p. 5. Staff noted that the LGAR has previously been used in PCA calculations with individual negative monthly load growth and thus has been part of the approved PCA calculations. *Id.* The Industrial Customers and Irrigators nonetheless argue this amount of increase is inappropriate and urged the Commission to disallow recovery of the amount adjusted by the LGAR

The Commission recently noted a potential inequity caused by an LGAR when retail load declines during the year, specifically mentioning Idaho Power's PCA. Order No. 31033, Case No. PAC-10-01. Because both variable and fixed costs of production embedded in rates are included in the LGAR, the effect of the LGAR when load declines "looks less like a power cost adjustment and more like a vehicle to restore lost revenue due to decreases in customer usage." Order No. 31033, p. 12. The Commission directed Staff to hold workshops to address the potential problem in the annual power cost adjustments for Idaho Power, PacifiCorp, and Avista, and "report continued justification for use of an LGAR when loads decline" to the Commission. *Id.*

Despite the problem presented by the LGAR when retail load declines, there is no basis in the record in this case to determine an appropriate amount that should be removed from the PCA calculation because of the LGAR. The Industrial Customers and Irrigators recommend removal of the entire $23.7 million resulting from the LGAR, but we cannot reasonably conclude from the record that the entire amount should be removed. After careful review of the record, the Commission will not remove the adjustment to the PCA true-up component resulting from the LGAR. The Commission expects Staff, the utilities, and interested parties to meet as soon as practicable to address an appropriate change to load growth adjustment mechanisms to eliminate a potential double recovery when loads decline.

The other challenge to the Company's calculation of the true-up piece of the PCA is Staff's adjustment to an interest calculation. Staff's recommended adjustment is based on its interpretation of Order No. 30715 issued in Case No. IPC-E-08-19, in which the Commission authorized Idaho Power to distribute base power supply costs in a specific manner. The Company redistributed those costs as authorized, but an unintended result was an increase in interest expense. Staff Comments, p. 4. The Commission intended no change in the cost of base power supply costs as a result of the redistribution, and Staff thus correctly removed $215,027 in interest expense from the true-up component of the PCA. We recognize that the Company may need to utilize a second spreadsheet to calculate the interest. Because shaping was authorized by the Commission to address reporting concerns of the Company, we believe this will create a minimal inconvenience. This adjustment only slightly changes the Company's proposed true-up component from 0.0888 cents per kWh to 0.0872 cents per kWh.

The third component of the PCA is the reconciliation, or true-up of the true-up from the previous year's PCA. The Company determined the unrecovered portion of the true-up from last year to be approximately $11.3 million, resulting in a PCA rate for this component of 0.0838 cents per kWh. Staff verified the accuracy of the Company's calculation, and no other party disputed it. Accordingly, the record regarding the reconciliation of the true-up piece of the PCA is undisputed, and we approve a rate of 0.0838 cents per kWh for this component of the PCA.

The three rate components of the PCA the Commission approves are 0.1404 cents per kWh, 0.0872 cents per kWh, and 0.0838 cents per kWh, resulting in a PCA rate of 0.3114 cents per kWh. This is a significant reduction in the current PCA rate of 1.4022 cents per kWh.

The Stipulation reviewed and approved by the Commission in Case No. IPC-E-09-30 authorized an increase in Idaho Power's base rates if the PCA recovery was significantly reduced. Most of the proposed increase in base rates is attributable to higher normal power supply costs, and as discussed in this Order, the Commission determined the cost for Bridger coal as presented by Idaho Power should not be removed from the base level power supply costs. This was the only dispute in the record to the Company's calculation of the appropriate increase to base rates. The Commission finds that the Company's proposed increase in base rates is consistent with the Commission-approved Stipulation and accordingly is approved. Attachment A to this Order sets forth the PCA rates for the period June 1, 2010 through May 31, 2011, and the changes to base rates approved by the Commission.

ORDER

IT IS HEREBY ORDERED that the Application of Idaho Power Company to implement its Power Cost Adjustment (PCA) rates effective June 1, 2010 through May 31, 2011, and to increase base rates, is approved as set forth in this Order. The three rate components of the PCA the Commission approves are 0.1404 cents per kWh, 0.0872 cents per kWh, and 0.0838 cents per kWh, resulting in a PCA rate of 0.3114 cents per kWh. Base rates are increased as set forth in Attachment A, with the increase spread to customer classes and rate components within each customer class on an equal percentage of revenue basis, except for residential and small commercial customer charges, which are to remain unchanged.

IT IS FURTHER ORDERED that Idaho Power prepare and file tariffs so that the rate decrease resulting from the PCA and the rate increase in base rates take effect on the same date, resulting in an overall decrease in customer rates of 6.49% average across all customer classes.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 28th day of May 2010.

JIM D. KEMPTON, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

MACK A. REDFORD, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

bls/O:IPC-E-10-12_ws2

IDAHO POWER COMPANY
CASE NO. IPC-E-10-12
COMMISSION ORDER
SUMMARY OF REVENUE IMPACT
Effective June 1, 2010

Schedule	Description	Current Billed Revenues (*)	PCA Decrease	%	Stipulated Base Rate Increase	%	New Billed Revenues	%
1	Residential Service	401,781,389	(54,402,417)	-13.54%	41,397,475	10.30%	388,776,447	-3.24%
3	Master Metered Mobile Home Park	377,782	(53,559)	-14.18%	38,521	10.20%	362,743	-3.98%
4	Residential Service Energy Watch	64,844	(8,897)	-13.72%	6,662	10.27%	62,609	-3.45%
5	Residential Service Time-of-Day	95,166	(13,074)	-13.74%	9,774	10.27%	91,866	-3.47%
7	Small General Service	16,136,075	(1,808,036)	-11.20%	1,725,790	10.70%	16,053,829	-0.51%
9S	Large General Service - Secondary	192,121,349	(33,710,474)	-17.55%	18,709,694	9.74%	177,120,569	-7.81%
9P	Large General Service - Primary	21,449,241	(4,330,188)	-20.19%	1,997,239	9.31%	19,116,292	-10.88%
9T	Large General Service - Transmission	131,951	(26,327)	-19.95%	12,337	9.35%	117,961	-10.60%
15	Dusk to Dawn Lighting	1,080,560	(72,056)	-6.67%	124,231	11.50%	1,132,735	4.83%
19S	Large Power - Secondary	425,371	(85,564)	-20.12%	39,659	9.32%	379,467	-10.79%
19P	Large Power - Primary	96,589,160	(21,280,271)	-22.03%	8,706,012	9.01%	84,014,902	-13.02%
19T	Large Power - Transmission	3,138,913	(719,052)	-22.91%	278,480	8.87%	2,698,341	-14.04%
24	Agricultural Irrigation	110,514,365	(17,857,396)	-16.16%	11,010,373	9.96%	103,667,342	-6.20%
40	Unmetered	1,185,082	(180,188)	-15.20%	119,895	10.12%	1,124,790	-5.09%
41	Street Lighting	2,727,141	(250,618)	-9.19%	302,421	11.09%	2,778,944	1.90%
42	Traffic Control	216,432	(43,770)	-20.22%	20,141	9.31%	192,803	-10.92%
Subtotal		848,034,823	(134,841,887)	-15.90%	84,498,704	9.96%	797,691,640	-5.94%
26	Micron	22,681,345	(5,583,986)	-24.62%	1,949,502	8.60%	19,046,861	-16.02%
29	Simplot	8,203,131	(2,038,624)	-24.85%	701,991	8.56%	6,866,498	-16.29%
30	DOE /INL	10,636,107	(2,714,268)	-25.52%	898,717	8.45%	8,820,556	-17.07%
32	HOKU	7,414,305	(1,729,409)	-23.33%	652,781	8.80%	6,337,677	-14.52%
Subtotal		48,934,887	(12,066,286)	-24.66%	4,202,991	8.59%	41,071,593	-16.07%
Total		896,969,710	(146,908,172)	-16.38%	88,701,695	9.89%	838,763,233	-6.49%

(*) Company's 2010-2011 Revenue Forecast
Excludes Energy Efficiency Rider Revenues