Office of the Secretary
Service Date
January 9, 2009

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION FOR APPROVAL OF CHANGES TO ITS POWER COST ADJUSTMENT (PCA) MECHANISM	)	**CASE NO. IPC-E-08-19**
	)	**ORDER NO. 30715**

On October 14, 2008, Idaho Power Company filed a Petition requesting a Commission Order approving changes to the Company's Power Cost Adjustment (PCA) mechanism as set forth in a Settlement Stipulation filed with the Petition. Consistent with a previous Commission Order, Idaho Power hosted workshops and settlement discussions addressing a number of issues and components of the PCA. The discussions resulted in a settlement signed by Idaho Power, Commission Staff, Micron Technology, the Industrial Customers of Idaho Power, the U.S. Department of Energy, and the Idaho Irrigation Pumpers Association. By this Order, the Commission approves the Stipulation and the changes to the PCA formula.

BACKGROUND

On May 30, 2008, the Commission issued Order No. 30563 in Case No. IPC-E-08-07, the Commission's annual Idaho Power PCA review for 2008/2009. In that Order the Commission noted, regarding a proposal to evaluate the PCA mechanism, that "Staff, Idaho Power, and the Irrigators all proposed workshops to address issues such as sharing methodology, forecasting methodology, the distribution of power cost deferrals, and load growth adjustment rates." The Commission directed Idaho Power to schedule PCA review workshops as soon as practicable. Order No. 30563, p. 8.

The first PCA workshop was held July 30, 2008, with representatives from Idaho Power, Commission Staff, Micron Technology, the Industrial Customers of Idaho Power and the U.S. Department of Energy participating. Two additional workshops were convened on August 13 and September 3, 2008 with irrigation customer class representatives joining the discussions. On October 14, 2008, Idaho Power filed the PCA Settlement Stipulation, developed as a result of the workshops and signed by all participating parties. The Company filed direct testimony of Gregory Said to support its request for approval of the Settlement Stipulation.

On November 13, 2008, the Commission issued a Notice of Application and Notice of Modified Procedure, establishing a period for the filing of written comments, to process Idaho Power's Petition. Written comments were filed by Commission Staff; no other party filed written comments. The record in this case thus consists of the Petition and Stipulation, the written testimony of Idaho Power's witness, and Staff's written comments. All support approval of the Stipulation.

THE STIPULATION

The Stipulation, filed as Exhibit No. 1 to Mr. Said's testimony, identifies six issues discussed in the workshops. For each issue, the Stipulation also describes the current PCA component or process and the proposed solution and rationale for the recommended change. The first issue is the sharing methodology that assigns purchased power costs or benefits to customers and shareholders. Since inception of the PCA, annual deviations in normalized power supply costs have been shared 90%/10% by customers and Company shareholders, respectively. If costs are below those anticipated, customers receive 90% of the difference. If costs are above those anticipated, customers pay 90% of the excess costs and the Company absorbs 10%. The Stipulation changes the sharing percentages to 95% and 5%. The Stipulation states that the reduced Company share remains sufficient to provide incentive for it to make careful resource acquisition decisions. Increases in power supply cost volatility and development of the Company's Risk Management Policy justify the change.

The second issue addressed in the Stipulation is the load growth adjustment rate (LGAR). The LGAR is part of the PCA mechanism intended to eliminate recovery of power supply costs associated with load deviations due to weather, growing customer totals or changing customer usage patterns. The current LGAR is calculated by multiplying the marginal cost of serving new load by one-half of the difference between current load and the load established in the Company's last rate case (Case No. IPC-E-07-08). The current rate is effectively $31.39 per MWh. The proposed new methodology recognizes that the Company incurs additional power supply costs to serve new load between rate cases and has no opportunity to collect those costs. By using three components – a return component, an expense component, and a revenue component of the production-related rate base – the new calculation recognizes the generation-related revenue that is collected from new load through rates. The proposed LGAR using the Stipulation's formula is $28.14 per MWh.

The third component addressed in the Stipulation is the PCA forecast. Currently the power supply forecast is based on estimated stream flow into Brownlee Reservoir. Power supply costs are estimated using load and natural gas prices as established in the Company's last rate case. Variations in the forecast from actual expenditures included in rates are collected the following year through the PCA. The Stipulation recognizes that the current forecast methodology has created unreasonably large true-ups at annual PCA reviews. The Stipulation states that forecasting power supply costs based on the Company's existing Operating Plan will improve forecasts and reduce future true-ups.

The fourth issue in the Stipulation is third-party transmission expense. The Stipulation states that third-party transmission expenses are a necessary component to facilitate purchases and sales of energy and thus should be considered to be a power supply expense, although they have not historically been tracked through the PCA. Because these expenses vary in relation to power purchases and sales, the Stipulation recognizes that they should reasonably be reflected in the PCA calculation.

The last issue resolved in the Stipulation is power supply expense distribution. Power supply expenses have been reported monthly based on a computer-modeled distribution. The Stipulation provides that the power cost distribution should be reported based on a monthly revenue shape. This adjustment will not affect the PCA calculation of the difference between actual power purchase expenses and the base net power supply expense, but will make comparisons easier for interim and annual financial reporting periods.

A final issue addressed in the Stipulation is not resolved. Currently PCA expenses are allocated to the different customer classes on an equal cents-per-kWh basis. The Stipulation provides that "this rate spread and revenue allocation needs to be reexamined following Idaho Power's current general rate case to determine if this methodology needs to be changed."

COMMISSION DISCUSSION

Only the proposed PCA modification to sharing percentages, the LGAR and transmission cost recovery impact power supply costs the Company will recover and the PCA rates that customers ultimately pay. We note initially that the PCA is symmetrical, that is, in above-average water years, power supply costs are below amounts anticipated and customers receive a credit. In below-average water years power supply costs are above expected costs and customers pay a surcharge. None of the changes agreed to in the Stipulation change the symmetry of the PCA.

PCA Sharing Ratio

The proposed change that could have the greatest impact on customer rates is the modification to the sharing percentages. By requiring the Company to pay a portion of the purchased power expense, set at 10% in the initial PCA formula, the Commission intended the Company to have a strong incentive to make prudent purchase decisions. There is now, however, significantly greater volatility in the purchased power markets than when the PCA was established in 1992. Evidence in this case demonstrates that modeled power supply scenarios in 1992 showed annual power supply cost volatility of approximately $100 million dollars, while power supply cost volatility modeled today is in the $330 million range. Applying the 10% Company share to power supply costs in 1992 resulted in a potential impact of approximately 50 basis points on Company earnings, and currently the potential impact is twice that amount. For the period 2001 through 2007, the Company's share of above-normal Idaho jurisdictional power supply costs totaled approximately $100 million or 95 basis points of equity return per year.

Idaho Power asserts that the existing PCA sharing percentage has affected its credit rating, resulting in higher borrowing costs that are ultimately paid by its customers. By lowering the sharing percentage, the Company maintains that credit ratings could improve and interest costs on debt could decline to the benefit of customers. Despite the Company's assertions, however, the Commission cannot find on the record in this case that a change in the PCA sharing ratio will assure that the Company's credit rating will improve to any particular level, or that lower interest rates on debt will generate quantifiable savings for customers. We do find that power supply cost volatility has increased significantly since the PCA was implemented, and that with increased volatility, a sharing percentage of 5% still provides strong incentive for the Company to make prudent power purchases.

The evidence also demonstrates that the Company has taken significant steps to include other interested parties, including Commission Staff, to collaboratively approach resource acquisition and mitigate overall power supply cost risks. The Company has developed a risk mitigation program with customer advisory oversight and has developed resource acquisition customer advisory groups for integrated resource planning and demand-side management. These programs that include customer and Commission Staff participation have helped direct the resource acquisition decisions of the Company and, to a greater extent than before, help to determine power supply costs that flow through the PCA.

Given the potential for lower interest costs, the increased volatility in power supply costs and improved collaborative resource acquisition processes of the Company, the Commission finds that a 95%/5% sharing split for customers and the Company is fair, just and reasonable.

The Load Growth Adjustment Rate (LGAR)

The treatment of growth-related power supply costs in the PCA has been an issue since the PCA was originally established. Because actual booked power supply costs, including growth-related costs, are compared to normalized power supply costs without load growth, growth-related costs are automatically included in the PCA without an LGAR. The Commission recognized this fact and originally established an LGAR of $16.84/MWh, a rate believed to generally reflect the cost to serve new load on the margin at the time. In 2007, the Commission increased the LGAR to $29.41/MWh to reflect a more current marginal cost to serve new load. In Case No. IPC-E-07-13, the Commission approved a comprehensive settlement that established the LGAR at its current level of $32.14/MWh. The rate is based on a marginal cost to serve new load of $64.28/MWh but is applied to only 50% of the load growth.

The LGAR of $28.14/MWh proposed in the Stipulation recognizes the magnitude and financial impact of serving new load at current marginal costs, the obligation of the Company to incur new load-related variable power supply cost between rate cases, and the inability of the Company to recoup these expenditures after the fact through general rates. The proposed LGAR also recognizes that revenue embedded in new customer rates will offset a significant portion of the growth-related power supply costs.

The Commission finds that the methodology using marginal power supply costs and power supply revenue embedded in rates as established in a general rate case provides a reasonable basis to calculate an appropriate LGAR. The agreement on an LGAR methodology in the Stipulation represents a reasonable compromise and resolves the issue in a fair and equitable manner for the Company and its customers. The specific methodology is shown in Exhibit A to the Settlement Agreement and is Exhibit 1 to this Order.

Third-Party Transmission Expense

Third-party transmission expenses have not historically been tracked through the PCA, even though they are directly associated with the level of off-system sales and purchases. These expenses are incurred by the Company when transmission is purchased from third parties outside the Company's transmission network, and the Stipulation recognizes that "third-party transmission expenses are a necessary component to facilitate purchases and sales of energy and are reasonably considered a power supply expense." Stipulation p. 8.

The Stipulation provides that the level of transmission costs approved by the Commission in the Company's most recent rate case is a reasonable basis for calculating transmission expenses in the PCA. For example, actual 2007 third-party transmission costs were in the $13 million range. If the Commission includes this amount in base rates set in the Company's pending rate case, it will also be used as the basis for determining extraordinary third-party transmission expense in the PCA in the future.

We find that third-party transmission costs are incurred in conjunction with market purchases and sales and should be tracked through the PCA like other variable power supply costs. Including third-party transmission expenses in the PCA is a straightforward treatment of power supply costs that fluctuate with power purchases and sales.

Forecast and Expense Distribution

The remaining issues addressed in the Stipulation do not affect the overall PCA cost responsibility between customers and shareholders. These issues are forecast of PCA power supply costs, reporting of power supply expenses during the year, and the rate spread/revenue allocation that has historically been used in the PCA. The Stipulation recognizes that the current PCA forecast is flawed and sends inaccurate and improper power supply price signals. Inaccuracies in river flow forecasts and the power supply modeling create errors in the power supply forecast when compared to actual power supply expenditures. In addition, the system load and the gas price forecast used in the power supply model are based on information established in the last general rate case. The combination of internal modeling inaccuracies and outdated load and gas price data has resulted in a significant underestimation of power supply costs and subsequent very large PCA true-ups.

The Stipulation recognizes that the Company's Operating Plan provides the best forecast available for use in the PCA. The Operating Plan is continually updated based on gas prices, loads, resources, water conditions and other power supply variables. It is the de facto forecast used by the Company to actually meet system load throughout the year. It is also an integral part of the Company's Risk Management Program and is subject to review by Staff and customers as part of the risk management customer advisory group. The Commission finds that Idaho Power's Operating Plan more accurately forecasts power supply costs, thereby sending a more accurate price signal to customers and should reduce the magnitude of subsequent PCA reconciliations.

The distribution of power supply expenses throughout the year used for comparison to actual expenses has historically been based on the monthly power supply model output. The evidence shows that this reporting process can create confusion for the financial community by inappropriately showing large swings between expected and actual earnings on a quarterly basis and earnings that eventually result on an annual basis. The Commission finds using the monthly revenue shape to report base net monthly power supply expenses will improve information disseminated to financial entities without sacrificing appropriate accounting for PCA purposes. Modeled power supply costs on a monthly basis will be tracked with PCA expense deferrals and reported to the Commission Staff.

Finally, the Commission approves the Stipulation provision calling for later investigation of the rate spread/revenue allocation that has historically been used in the PCA. Traditionally, PCA costs have been allocated on an energy-only basis in Commission-approved cost of service studies, and thus have been spread on an equal cents-per-kWh basis to all customer classes. Some parties in this case argue that if variable power supply costs tracked through the PCA are allocated in a general rate case based on demand and energy, then extraordinary PCA costs should also be allocated on both demand and energy. We direct the Company and interested parties to review this issue further following conclusion of the Company's current rate case.

CONCLUSIONS

For the reasons cited above, the Commission finds the terms of the Stipulation to be fair, just and reasonable, and we approve the Stipulation and the changes to the PCA methodology set forth in the Stipulation. We find the Stipulation filed by the Company in this case represents a fair and reasonable resolution of the issues originally identified by the Commission and as discussed in the workshops.

ORDER

IT IS HEREBY ORDERED that the Petition of Idaho Power Company for approval of the Stipulation and changes to its Power Cost Adjustment mechanism, as set forth in the Stipulation filed with the Petition, is approved.

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 9th day of January 2009.

MACK A. REDFORD, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

~~JIM D.~~ KEMPTON, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

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EXHIBIT A
LOAD GROWTH ADJUSTMENT RATE ("LGAR") CALCUATION
SETTLEMENT AGREEMENT

The Parties agree to use the following methodology to determine the Load Growth Adjustment Rate: The LGAR will consist of three components:

1. A return component based upon production-related rate base.
2. An expense component based upon production-related rate base.
3. A revenue component based upon production-related rate base.

Component 1: Production-Related Rate Base

The Production-Related Rate Base component would be the result of an IPUC order in general revenue requirement proceedings. As an example from the current Company request in Case No. IPC-E-08-10, page 1 of Exhibit No. 54 contains the demand and energy components of rate base allocated to the production function.

Demand	$428,477,746
Energy	$501,479,100
Total	$929,956,845

Assuming the Commission approved cost of capital structure is 50 percent debt and 50 percent equity and the approved overall rate of return is 8.55 percent:

Rate base	$929,956,845 @ 8.55%	= $79,511,310
Debt	$464,978,423 @ 5.85%	= $27,201,125
Equity	$464,978,423 @ 11.25%	= $52,310,185

The Equity piece is grossed-up for taxes (1.642 multiplier)

Grossed-up Equity	$ 85,893,324
Debt	$ 27,201,125
LGAR Component 1	**$113,094,449**

Component 2: Production-Related Expenses

The Production-Related Expenses component would be the result of an IPUC order in general revenue requirement proceedings. An example from the current Company request in Case No. IPC-E-08-10, page 2 of Exhibit No. 54 contains the demand and energy components of expenses allocated to the production function.

Demand	$ 84,862,274
Energy	$372,833,595
Total	$457,695,869

The Parties recognize that included in this allocation are expenses related to customer service, and general and administrative expenses that are not directly associated with production and are reasonably removed. These amounts can be found in Exhibit 53 page 61, lines 467 through 485 and Exhibit 53 page 66, lines 489 through 520. The sum of these exclusions is $40,508,666.

Total from above	$457,695,869
Less exclusions	$ 40,508,666
LGAR Component 2	**$417,187,203**

Component 3: Production-Related Revenues

The Production-Related Revenues component would be the result of an IPUC order in general revenue requirement proceedings. An example from the current Company request in Case No. IPC-E-08-10, page 3 of Exhibit No. 54 contains the demand and energy components of revenues allocated to the production function.

Demand	$ 950,801
Energy	$106,270,965
LGAR Component 3	**$107,221,766**

LGAR Rate

The Load Growth Adjustment Rate (LGAR) is equal to the result of adding Components 1 and 2, subtracting Component 3, and finally dividing by the Commission approved Idaho jurisdictional firm load.

Component 1:	$113,094,449	
Component 2:	$417,187,203	
Component 3:	$107,221,766	
(1) + (2) – (3)	$423,059,886	
Idaho jurisdictional load	15,036,726 MWh	(Exhibit 51)
LGAR Rate	**$28.14/ MWh**	

Exhibit 1
Case No. IPC-E-08-19
Order No. 30715