ORDER NO. 08-238

ENTERED 04/28/08

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 195

In the Matter of	)	
	)	
IDAHO POWER COMPANY	)	ORDER
	)	
Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon.	))))	

DISPOSITION: STIPULATION APPROVED; POWER COST ADJUSTMENT MECHANISM ADOPTED

In this order, we approve a Power Cost Adjustment Mechanism (PCAM) for Idaho Power Company (Idaho Power or Company) applicable to rates for the Company's Oregon customers.

INTRODUCTION

In docket UE 167, we recognized that Idaho Power's system is uniquely reliant on hydroelectric generation and acknowledged that, in Oregon, the Company was limited in its ability to amortize deferred costs. Such deferrals adversely impact the Company's ability to recover net power supply expenses in a timely manner. We therefore directed Idaho Power to work with the Commission Staff (Staff) and other interested parties to consider whether there was a more effective regulatory mechanism for Idaho Power to recover its allowable power costs.[1] This proceeding, which authorizes the Company to add a provision in its rate schedule for both a PCAM and an Annual Power Cost Update (APCU), is the result of those efforts.

ORS 757.210(1) provides for a provision in a utility's rate schedule for an "automatic adjustment clause" that provides for rate changes without a hearing to reflect costs incurred, taxes paid to units of government or revenues earned by a utility that is subject to review by the Commission at least once every two years.

[1] Order No. 05-871, entered July 28, 2005, at 7.

On August 17, 2007, Idaho Power filed an application (Application) pursuant to ORS 757.210(1) for approval of an automatic adjustment clause in the form of a proposed PCAM, accompanied by supporting testimony and exhibits. On August 21, 2008, the Citizens' Utility Board of Oregon (CUB) filed a Notice of Intervention. A General Protective Order, Order No. 07-427, was entered by the Administrative Law Judge (ALJ) on October 4, 2007. On October 14, 2007, a prehearing conference was held at which the Company, CUB and Staff agreed upon a procedural schedule which was adopted by the ALJ. No other parties participated in this docket. On October 29, 2007, Idaho Power filed supplemental direct testimony.

On motion by the parties filed November 28, 2007, the ALJ suspended the schedule to allow the parties to conduct further settlement negotiations prior to the submission of further testimony. As a result of the negotiations, on March 14, 2008, Idaho Power, CUB and Staff filed a stipulated agreement (Stipulation), resolving all of the issues arising from and relating to the Idaho Power Application, supported by joint testimony of all of the parties.[2] A copy of the Stipulation is affixed to this order as Appendix A and is adopted as an integral part hereof. On March 24, 2008, Idaho Power filed a tariff and supporting supplemental testimony to conform to the methodologies for both the October Update and the March Power Cost Forecast agreed to by the parties in the Stipulation.

THE STIPULATION

The parties agree that the Commission should adopt both an APCU and a PCAM for Idaho Power. The parties state that the APCU and PCAM will operate to allow Idaho Power the ability to recover its power cost expenses in a fair and reasonable manner.

Although we refer to the Stipulation itself for the official and more detailed explanation of both the APCU and the PCAM, they are briefly summarized below:

APCU

The proposed APCU will constitute an "automatic adjustment clause" within the meaning of ORS 757.210(1). The APCU is comprised of two primary components: an October Power Cost Update (October Update) and a March Power Cost Forecast (March Forecast).

1. October Update. In October of each year, Idaho Power will file an update that provides calculations for the Company's net power supply expense on a normalized basis and unit basis. The filing will have an effective date of June 1 of the following year, based on an April through March test period.

[2] Staff/Idaho Power/CUB/100, Owings/Youngblood/Brown/1-13.

The parties agree on numerous features used to calculate the October Update. For example, the Stipulation states that the Company's power supply model (AURORA) will be used to determine the net power supply average, and that the wholesale electricity prices for purchased power and surplus sales determined by AURORA will be replaced with a calculated average forward electric price curve, subject to certain adjustments. The parties also agree how the "normalized" volume of purchased power and surplus sales determined by AURORA will be repriced relative to Mic-C prices, and what variables will be updated annually.

2. March Forecast. In March of each year, Idaho Power will file a forecast, with a June 1 effective date, that reflects the Company's estimate of expected power supply expenses for the April through March test period with the most recent updates for 10 separate variables, including the separately defined forward price curve.

PCAM

Each February of each year, beginning in 2009, Idaho Power will file an Annual Power Supply Expense True-up, which will implement the PCAM by calculating the deviation between actual net power supply expenses and those expenses recovered through the Combined Rate for the same period. For purposes of the true-up, power costs are first calculated on a total system basis and then allocated to Oregon based on an allocation factor.

Power supply deviations are calculated using an asymmetrical deadband. A positive deviation (actual expenses greater than those recovered) will be reduced by the dollar equivalent of 250 basis points of Return on Equity (ROE) from Idaho Power's last general rate proceeding. Ninety (90) percent of any excess power supply cost would be deferred for possible recovery. A negative deviation (actual expenses lower than those recovered) will be reduced by the dollar equivalent of 125 basis points of ROE. Ninety (90) percent of any power supply savings would be deferred for possible refund to customers.

Eligible power supply expense deviations will be added to an annual true-up balancing account at the end of each 12-month period ending in December, along with 50 percent of the annual interest calculated at the Company's authorized cost of capital. Interest will accrue on the balancing account at the Commission-authorized rate for deferred accounts.

Before any amounts of excess power supply true-ups are approved for subsequent recovery or refund, the Commission will apply an earnings test. If Idaho Power's earnings are within 100 basis points of its authorized ROE, no true-up amounts will be added to the balancing account for that year. If earnings are 100 basis points below its authorized ROE, the Company will be allowed to add 90 percent of the eligible amounts to the balancing account, up to an earnings level that is 100 basis points less than its authorized ROE. If earnings are more than 100 basis points above its authorized ROE, the Company will be allowed to include 90 percent of the eligible amounts as a credit to the balancing account, down to an earnings level that is 100 basis points above its authorized ROE.

DISCUSSION

Idaho Power relies on hydroelectric generation to provide nearly one half of its load. Rain and snowfall are highly variable and therefore the Company's power supply expenses are subject to very significant variations on a regular basis. Moreover, the financial impact of this variation is asymmetric: poor hydro conditions put upward pressure on overall power costs to a greater extent than good hydro conditions lower them.

Under Oregon's deferral statute, ORS 757.259(8), the Commission may not authorize amortizations of deferred amounts with an overall average rate impact of over 6 percent. This prohibition results in exceedingly long delays between the time the Company incurred excess power costs and their recovery, despite the Commission's grant of the Company's requests for deferred power cost expenses for 2005-2006 and 2006-2007.[3]

In docket UE 167, the Commission specifically directed Idaho Power, Staff and other interested parties to find a regulatory solution to the problem of recovery of allowable power costs. Informal talks were held by the parties during which alternative proposals were discussed and refined. These proposals culminated in the filing of the Company's Application. Further settlement discussions and conferences were held subsequent to the filing of the Application, resulting in significant changes to the recovery mechanisms contained in the Application in the Stipulation document arising out of the settlement.[4] The solution presented by the Stipulation achieves the goal set out for the parties in UE 167.

We have reviewed the Stipulation and the proposed tariff implementing the terms thereof and find them to be in accordance with the statutes and our rules and consistent with the public interest. We agree with the parties that the APCU and PCAM will benefit Idaho Power and its customers by allowing it to recover its prudently incurred power expenses on a timely basis. The Stipulation should be adopted.

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[3] In 2001, the Commission granted Idaho Power's application to defer approximately $4 million in excess power costs that were incurred during the Western Energy Crisis of 2000-2001. The Company began amortizing those amounts in May, 2001, and anticipates that they will not be fully recovered until sometime in 2010.

[4] Staff/Idaho Power/CUB/100, Owings/Youngblood/Brown/4.

ORDER

IT IS ORDERED that the Stipulation submitted by Idaho Power Company, Commission Staff and the Citizens' Utility Board of Oregon, attached as Appendix A, is adopted.

Made, entered and effective APR 2 8 2008.

Lee Beyer
Chairman

Ray Baum
Commissioner

John Savage
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 195

In The Matter of the Application of IDAHO POWER COMPANY for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon	**STIPULATION**

INTRODUCTION

The parties to this Stipulation are Idaho Power Company ("Idaho Power" or the "Company"), Staff of the Public Utility Commission of Oregon ("Staff") and the Citizens' Utility Board of Oregon ("CUB"), (collectively, the "Parties"). The Parties represent all parties to this docket.

By entering into this Stipulation, the Parties intend to resolve all issues arising from and relating to Idaho Power's Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon (hereinafter, the "Application").

BACKGROUND

Idaho Power filed its Application on August 17, 2007, supported by the testimony of Company witnesses, Michael J. Youngblood and Gregory W. Said.

CUB filed its Notice of Intervention on August 21, 2007.

On October 4, 2007, Administrative Law Judge Alan Arlow presided over a prehearing conference at which the Parties agreed to a procedural schedule.

On October 29, 2007, Idaho Power filed supplemental direct testimony.

The Parties met for settlement discussions on November 5, 2007. At the end of that conference, the Parties agreed to continue settlement discussions at an additional settlement conference which was held on December 7, 2007, followed by a teleconference on December 12, 2007. A final settlement conference was held on March 10, 2008. As a result of these settlement negotiations, the Parties enter into this Stipulation.

STIPULATION

1. The Parties agree that the Commission should adopt for Idaho Power an Annual Power Cost Update (or, alternatively "APCU") and a Power Cost Adjustment Mechanism (or, alternatively, "PCAM"). The APCU will be comprised of the following two components: An October Power Cost Update ("October Update") and March Power Cost Forecast ("March Forecast"). The Parties agree that the APCU and PCAM, as more particularly described below, will operate to allow Idaho Power to recover its power cost expenses in a fair and reasonable manner.

Annual Power Cost Update

2. The Annual Power Cost Update will constitute an automatic adjustment clause within the meaning of ORS 757.210(1).

APCU-October Update

3. In October of each year, the Company will file its October Update with an effective date of June 1 of the following year. This filing, which will be based on a test period of the following April through March (the "April through March Test Period" or "Test Period"), will reflect a normalized look, on a system wide basis, at the Company's net power supply expenses ("NPSE"). A normalized look means the October Update will incorporate data reflecting normal loads and average costs associated with multiple stream flow conditions as further detailed in paragraph 4.

4. The Parties agree that the following method will be used to calculate the October Update:

a. The output of the Company's power supply model (AURORA or its successor) will be used to determine the net power supply average dispatch for normal loads and an average of stream flow conditions.[1]

b. The wholesale electric prices for purchased power and surplus sales determined by the Company's power supply model will be replaced with an average forward electric price curve calculated from the previous 12 months (the previous October through the September prior to the October filing) of daily Mid-Columbia heavy load (Mid-C HL) and light load (Mid-C LL) forward price curves for the period starting in April immediately following the April through March Test Period. Forward prices will be adjusted for inflation back one year using the most recent Global Insight Producer Price Index for Electric Power. For example: the October 2007 filing of normal power supply expenses, which would use the Test Period April 2008 – March 2009, would incorporate the average of the daily price curves collected from October 2006 through September 2007 for the period April 2009 – March 2010. This average forward price curve would then be adjusted for inflation back one year to April 2008 – March 2009 (the Test Period) using the most recent Global Insight Producer Price Index for Electric Power.

c. The volume of purchased power and surplus sales determined from the output of the Company's power supply model normalized run will be re-priced in the following manner:

[1] Should the Company employ a model other than Aurora to calculate power costs, the Parties will examine the new model and the impact use of that model might have on the APCU and the PCAM described herein. The Parties agree to reserve the right to advocate for a different PCAM and APCU if the Company replaces Aurora with a different model.

- Purchased Power
  - Heavy Load – 3.9% above average Mid-C HL prices
  - Light Load – 7.1% above average Mid-C LL prices
- Surplus Sales
  - Heavy Load – 3.6% below average Mid-C HL prices
  - Light Load – 6.6% below average Mid-C LL prices

5. The October Update unit costs ("October Update Rate")for power supply expense will be the Base Power Costs divided by Normalized Sales. Base Power Costs are the total power supply expense dollars calculated in accordance with paragraphs 4 and 8. Normalized Sales are described in paragraphs 6 and 7.

6. Normalized Sales for the Test Period are to be determined in accordance with the methodology employed in the most recently acknowledged Integrated Resource Plan ("IRP"). Normalized Sales are used to determine the rate, per MWh, required to recover normalized power supply expenses.

7. Normalized Load is the amount of energy in megawatt-hours required to be generated in order to meet customer demand on a normal basis, and is measured at the generation sources. The difference between Normalized Loads and Normalized Sales is the transmission and distribution losses between the generation source and the metered customer sales. Normalized Load for the Test Period is to be determined in accordance with the methodology employed in the most recently acknowledged IRP.

8. The Parties agree that the following variables will be updated for the October Update.

    a. Fuel prices and transportation costs;

    b. Wheeling expenses;

    c. Planned outages and forced outage rates;

    d. Heat rates;

e. Forecast of Normalized Sales and Normalized Load as described in paragraph 6 and 7;

f. Contracts for wholesale power and power purchases and sales;

g. Forward price curve as defined in paragraph 4(b);

h. PURPA contract expenses; and

i. The Oregon state allocation factor.

j. Updates to plant capabilities and acquisitions or changes to resources effective for the Test Period.

9. In the event that the Commission, in a future general rate case, adopts a different methodology for establishing the base rate component related to power supply expenses, the Parties agree that the October Update methodology should be adjusted to conform with the methodology approved in the general rate proceeding.

10. Prior to the initial October Update, by April 18, 2008, the Company will file a report showing that the Company is not earning more than its allowed rate of return. The showing will use a preliminary 2007 Results of Operations report with adjustments to reflect April 2008 through March 2009 normalized net power supply costs and the resulting revised tax expenses. The normalized net power supply costs are to be calculated using the methodology for the October Update described above, and then multiplied by 2007 Normalized Loads. The Parties reserve the right to recommend a rate reduction based on the results of this earnings review.

APCU-March Forecast

11. In March of each year the Company will file its March Forecast with an effective date of June 1 following the filing. The March Forecast filing will reflect the Company's estimate of expected power supply expenses for April through March Test Period, allowing for the most recent updates to the following variables:

a. Fuel prices and transportation costs;

b. Wheeling expenses;

c. Planned outages and forced outage rates;

d. Heat rates;

e. Forecast of Normalized Sales and Normalized Loads, updated only for known significant changes since the October Annual Power Cost Update filing.

f. Forecast Hydro generation from stream flow conditions using the most recent water supply forecast from the Northwest River Forecast Center in Portland, Oregon, and current reservoir levels;

g. Contracts for wholesale power and power purchases and sales;

h. Forward price curve as defined in paragraph 12

i. PURPA contract expenses; and

j. The Oregon state allocation factor.

12. The updated forward price curve used for market purchased power and surplus sales in paragraph 11(h) will be the most recent monthly forward price curve, as of the date of the filing, for the April through March Test Period, with heavy load and light load mid-Columbia prices modified in the following manner:

- Purchased Power
  - Heavy Load – 3.9% above average Mid-C HL prices
  - Light Load – 7.1% above average Mid-C LL prices
- Surplus Sales
  - Heavy Load – 3.6% below average Mid-C HL prices
  - Light Load – 6.6% below average Mid-C LL prices

13. A single water condition run of the power supply model for the April through March Test Period, with updated stream flow conditions and reservoir levels as described in paragraph 11(f), will be used to determine the March Forecast of net power supply expense.

14. The unit cost of the March Forecast will be the March Forecast Rate. The March Forecast Rate will be the Forecast Power Costs determined by the process described in paragraphs 11-12, divided by the Forecast Sales in megawatt-hours ($/MWh) as described in paragraph 11(e).

15. The Sales Adjusted Forecast Power Cost Change is the March Forecast Rate less the October Update Rate, the result multiplied by the Forecast Sales.

16. The Forecast Change Allowed is 95% of the Sales Adjusted Forecast Power Cost Change .

17. The March Forecast Rate Adjustment is the Forecast Change Allowed divided by Forecast Sales.

18. The Combined Rate is the sum of the October Update Rate and the March Forecast Rate Adjustment. The Combined Rate is part of the Effective Rate Change taking place on June 1 for the June through May power cost year.

Power Cost Adjustment Mechanism

19. In February of each year, beginning in February of 2009, the Company will file the Annual Power Supply Expense True-up which will implement the Power Cost Adjustment Mechanism. This filing will calculate the deviation between actual net power supply expenses incurred for the preceding January through December period and the net power supply expenses recovered through the Combined Rate for that same period. For the purposes of the true-up, power costs are first calculated on a total system basis and then allocated to Oregon based on the allocation factor.

20. The Actual Unit Cost for net power supply expenses incurred will be the total Actual (system wide) Power Supply Expenses incurred divided by the Actual Sales. Actual Power Supply Expenses include FERC Accounts 501 (Fuel-Coal), 547 (Fuel-Gas), 555 (Purchased Power), and 447 (Sales for Resale).

21. The annual deviation between the Combined Rate and the Actual Unit Cost times the Annual Sales is multiplied by the current Oregon allocation factor in order to determine the Oregon Allocated Power Cost Deviation.

22. A power supply expense deadband (based upon the Company's authorized ROE from its last general rate case and using the rate base measured on an Oregon basis from the most recent Oregon Results of Operations report) is applied to the Oregon Allocated Power Cost Deviation as follows:

a. A positive deviation (actual net power supply expenses greater than those recovered through the Combined Rate) constitutes an excess power supply expense. This expense is first reduced by a deadband that is the dollar equivalent of 250 basis points of ROE (Oregon basis). If, after applying the deadband, there is still excess power supply cost, 90% of that amount will be deferred for possible recovery by the Company through the mechanism described below.

b. A negative deviation (actual net power supply expense less than those recovered through the Combined Rate) is a power supply expense savings. This savings is reduced by a deadband that is the dollar equivalent of 125 basis points of ROE (based upon the Company's authorized ROE from its last general rate case and using the rate base measured on an Oregon basis from the most recent Oregon Results of Operations report). If, after applying the deadband, there is still remaining power supply savings, 90% of the savings amount will be deferred for possible refunding by the Company to the customers through the mechanism described below.

23. Subject to the Earnings Test below, eligible power supply expense deviations calculated by the process described above (after deadband and sharing) will be added to the

Annual Power Supply Expense True-Up Balancing Account (True-Up Balancing Account) at the end of each 12-month period ending December, along with 50 percent of the annual interest calculated at the company's authorized cost of capital. Interest will accrue on the balancing account at the Commission-authorized rate for deferred accounts.

24. The Annual Power Expense True-Up is a unit cost rate ($/MWh), calculated as the excess power supply costs or savings in the Annual Power Supply Expense True-Up Balancing Account, divided by the Forecast Sales for the upcoming Test Period, divided by the Oregon allocation factor.

Earnings Test

25. Before any amounts of excess power supply true-ups are approved for inclusion in the Annual Power Supply Expense True-Up Balancing Account for subsequent recovery or refund in rates, the Commission will apply an earnings test. If Idaho Power's earnings are within +/- 100 basis points of its authorized ROE, as measured from an Oregon Results of Operations report for the twelve months ended December 31 of the previous year, excluding amounts that would be added to the Annual Power Supply Expense True-Up Balancing Account, no true-up amounts will be added to the Balancing Account for that year. If the Company's current earnings are more than 100 basis points below its authorized ROE (Oregon basis), the Company will be allowed to add the excess power supply true-up costs to the Annual Power Supply Expense True-Up Balancing Account, after application of the power supply expense deadband and 90%-10% sharing (customers bear 90 percent and the Company bears 10 percent), up to an earnings level that is 100 basis points less than its authorized ROE. If the Company's earnings are more than 100 basis points above its authorized ROE (Oregon basis), it will be required to include the amount in the Annual Power Supply Expense True-Up Balancing Account as a credit, after application of the deadband and 90%-10% sharing, down to the authorized ROE plus 100 basis points threshold.

Effective Rate Change

26. The Effective Rate Change equals the Combined Rate (the sum of the updated October Update Rate, filed for in October, and the March Forecast Rate Adjustment, filed for in March) plus or minus the Annual Power Supply Expense True-up Rate (subject to the provisions of the Earnings Test and Oregon law regarding deferrals).

PURPA Expenses

27. All PURPA related power supply expenses will be treated the same as all other non-PURPA power supply expenses.

Terms of Agreement

28. The Stipulation is offered into the record of this docket pursuant to OAR 860-014-0085. The Parties agree to support the Stipulation throughout this proceeding and any appeal, to provide witnesses to sponsor the Stipulation at any hearing held in this docket and recommend that the Commission issue an order adopting the settlement contained herein.

29. The Parties have negotiated the Stipulation as an integrated document. If the Commission rejects any material portion of the Stipulation or conditions its approval upon the imposition of additional material conditions, any party disadvantaged by such action shall have the rights in OAR 860-014-0085 and shall be entitled to seek reconsideration of the Commission's order.

30. By entering into this Stipulation, no Party shall be deemed to have approved, admitted to, or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of the Stipulation.

31. This Stipulation may be executed in counterparts and each signed counterparty shall constitute an original document.

32. Each Party enters into the Stipulation on the date below.

STAFF

By:______________________

IDAHO POWER COMPANY

By:______________________

CITIZENS' UTILITY BOARD

By:______________________

Dated: March 14, 2008

32. Each Party enters into the Stipulation on the date below.

STAFF

By: Bonnie B. Tatom
3-14-08

IDAHO POWER COMPANY

By:__________________

CITIZENS' UTILITY BOARD

By:__________________

Dated: March 14, 2008