

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549**

FORM 8-K

CURRENT REPORT

**PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934**

Date of Report (Date of earliest event reported): February 24, 2010

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices and registrants' telephone number	IRS Employer Identification Number
1-14465	IDACORP, Inc.	82-0505802
1-3198	Idaho Power Company 1221 W. Idaho Street Boise, ID 83702-5627 (208) 388-2200	82-0130980

State or Other Jurisdiction of Incorporation: Idaho

None

Former name or former address, if changed since last report.

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2.):

- Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

IDACORP, Inc.
IDAHO POWER COMPANY
Form 8-K

Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.

Short-Term Incentive Compensation

On February 26, 2010, the Compensation Committee (the “Committee”) of the Board of Directors (the “Board”) of IDACORP, Inc. (“IDACORP”) established 2010 short-term incentive award opportunities for executive officers and senior managers under the IDACORP, Inc. Executive Incentive Plan (the “Plan”) and amended Exhibit A to the Plan to reflect the performance goals for 2010. The Board approved Exhibit A as amended and the 2010 short-term incentive award opportunities at its meeting on February 26, 2010. A copy of Exhibit A as amended is filed as Exhibit 10.1 hereto. Filed as Exhibit 10.2 and incorporated herein by reference is the Executive Incentive Plan NEO 2010 Award Opportunity Chart indicating the 2010 short-term award opportunities for those executive officers who were named executive officers in the 2009 proxy statement for the Annual Meeting of Shareholders of IDACORP (the “NEOs”), except for Thomas R. Saldin and James C. Miller who retired in 2009.

The terms of the Plan provide for cash incentive award opportunities based upon IDACORP and Idaho Power Company (“IPC”) performance measures with a threshold, target and maximum level. The amount of incentive is calculated by multiplying base salary by the product of the approved incentive percentage and the combined multiplier. The maximum payout is 200% of target.

The goals for 2010 are a combination of (i) operational and customer service goals for IPC (weighted 30%) and (ii) consolidated net income for IDACORP, as adjusted (weighted 70%).

The first goal has two components: (i) customer satisfaction and (ii) network reliability for general service customers. Achievement of customer satisfaction, as measured by the customer relationship index, at the threshold level will result in a multiplier of 7.5%, at the target level will result in a multiplier of 15% and at the maximum level will result in a multiplier of 30%. Achievement of network reliability for general service customers (which is based on the number of service interruptions more than five minutes in duration and also requires that no more than 10% of customers have more than six interruptions) at the threshold level will result in a multiplier of 7.5%, at the target level will result in a multiplier of 15% and at the maximum level will result in a multiplier of 30%.

Achievement of the second goal, IDACORP consolidated net income, as adjusted, at the threshold level will result in a multiplier of 35%, at the target level will result in a multiplier of 70% and at the maximum level will result in a multiplier of 140%. Net income as reported in IDACORP’s audited financial statements will be reduced by a percentage of any tax benefits over a predetermined dollar amount, without including the effects of sharing with Idaho

customers any return on equity in excess of 10.5 percent pursuant to the January 2010 Idaho settlement agreement.

Participants who retire, die or become disabled during the year remain eligible to receive a prorated award to the extent performance goals are met. Participants who terminate employment for other reasons are not eligible for an award, unless otherwise determined by the Committee. The Committee assesses the extent to which goals have been achieved and recommends payment amounts to the Board. The Committee's recommendation may reflect downward adjustment of awards in light of such considerations as the Committee may deem relevant. An award is deemed earned and vested only when the Board approves payment of the award to the participant. No award may be paid under the Plan if there is no payment to employees under the IDACORP Employee Incentive Plan or if net income is less than the Board-approved dividend for IDACORP common stock for the calendar year to which the award relates.

In the event of a change in control, the Board has discretion, with respect to outstanding awards, to provide for assumption or substitution of the awards by the successor entity or to adjust performance goals and other terms of the awards as it deems appropriate. Under certain circumstances, the Board may approve vesting of all or a portion of the awards at target or another level determined by the Board or take such other action as the Board deems appropriate.

Participants who terminate employment for reasons other than cause after the date of a change in control shall be vested in either a prorated award or a full award in an amount determined by the Board.

Item 8.01 Other Events

Oregon General Rate Case Order

As previously reported, on December 17, 2009, Idaho Power Company (IPC) entered into a stipulation (Stipulation) with all active parties to IPC's general rate case filed with the Public Utility Commission of Oregon (OPUC) on July 31, 2009. On February 24, 2010, the OPUC issued its order approving the Stipulation, with certain exceptions related to residential rate design (Order). The Order and Stipulation are furnished as exhibits hereto.

Following is a summary of the main terms of the Stipulation as approved by the Order.

Rate Settlement. IPC's annual revenue requirement in Oregon will increase by approximately \$5 million, for an overall rate increase in Oregon of approximately 15.4%. IPC implemented the approved rate increase on March 1, 2010, as authorized in the Order.

Rate of Return. IPC's return on equity is set at 10.175% for the Oregon jurisdiction, and its overall rate of return is set at 8.061% in Oregon. IPC's previously authorized rate of return in Oregon was 7.83%, and its requested rate of return in its general rate case filing was 8.68%.

Advance Metering Infrastructure (AMI) Communication Equipment. The capital expense associated with IPC's AMI equipment is not included in the Stipulation rate increase, since AMI

equipment has not yet been implemented in IPC's Oregon service territory. IPC will make a request to recover any prudently incurred investment in AMI equipment in Oregon in the future. In the event IPC receives smart grid funding for AMI equipment under the American Reinvestment and Recovery Act, such funds will be used as an offset to IPC's AMI investment, reducing the net rate base upon which future returns will be determined.

Net Power Supply Expense. On a going forward basis, the level of net power supply expense recovery included in IPC's base rates is \$10.94 per MWh, and that rate will become the base from which future IPC Annual Power Cost Update rates will be determined.

Pension Expense. IPC will continue to account for pension expense on an accrual basis, a practice consistent with Statement of Financial Accounting Standards (SFAS) 87. It is not practicable for IPC to account for the difference in capitalized labor charges between jurisdictions with a fixed asset system, but IPC has historically capitalized a portion of its labor costs, including SFAS 87 expense. In order to simulate the historic accounting without creating an undue burden on IPC, IPC will be allowed to record the capital portion of its SFAS 87 expense as a regulatory asset to be amortized in a manner consistent with the depreciation of electric plant in service and revised by the OPUC for inclusion in rates in a subsequent rate proceeding. The capital portion of pension expense in the fixed-asset system will be removed from net plant to prevent double recovery of pension expenses.

The approved revenue requirement in the Order includes an SFAS pension expense. Going forward, the OPUC should recognize both a regulatory asset associated with the capital portion of pension expense and the non-capital pension expense component when determining the Company's revenue requirement. If this provision is adopted, IPC will withdraw its request to account for its pension expense on a cash basis.

Marginal Cost Methodology/Functionalization of Production Costs/Revenue Spread. IPC's marginal cost approach to allocating costs is appropriate and will be adopted with two exceptions: (1) at this time, transmission-related revenue requirement will be classified as 75percent demand-related and 25percent energy-related for the purpose of allocation to customer classes and (2) IPC has historically separated its embedded production costs into energy and demand components prior to their allocation. Instead, the functionalized production revenue requirement will be allocated directly and on the basis of each schedule's combined share of marginal demand and energy costs. Because a pure cost of service revenue requirement allocation would result in relatively large increases for Agricultural Irrigation Service and Traffic Control Lighting Service, the increases for those customer classes are capped at 75 percent of their cost of service, with the revenue shortfall being spread to all other customer classes with the exception of Large Power Service-Transmission Voltage Level and Area Lighting Service, which receive no increase.

Rate Design. IPC will utilize the rate design as proposed in its general rate case filing, with certain exceptions pertaining to IPC's residential service charge, residential block rate pricing, and small general service customer energy charges, all as described in the Stipulation. Also, see the "Objections to the Stipulation" discussion below regarding the Citizens' Utility Board of Oregon (CUB) objections related to residential rate design.

Other Provisions. The Order approves the changes to IPC's Oregon rules as set forth in the Stipulation. These rules include IPC's Rule F (Service Connection and Discontinuance), Rule H (New Service Attachments and Distribution Line Installations or Alterations) and Rule K (Customer's Load and Operations). The Order also approves the Stipulation provisions relating to IPC's service to Schedule 19 customers. The Order further references the agreement by the Oregon Industrial Customers of Idaho Power to remove its service quality issue from this proceeding and pursue it in a separate docket.

Objections to the Stipulation. CUB objected to the residential rate design portion of the Stipulation. The Order addresses CUB's objections relating to seasonal rates, tiered residential rates, customer service charge, reducing subsidies to irrigation customers, and length of billing cycles. In some cases the Order approves the treatment of these items as recommended in the Stipulation, and in other cases different treatment is ordered by the OPUC, as follows:

1. The Stipulation recommends the adoption of seasonal rates, including higher rates for residential customer usage above 1,000 kWh per month during summer months. The OPUC declines this recommendation in the Order, and instead calls for the issue to be addressed in a separate docket.
2. IPC currently has a two-tiered residential rate structure in Oregon, with the first rate block of lower rates extending up to 300 kWh per month. The Stipulation recommends raising this first rate block to 1,000 kWh per month, to cover the basic level of electricity usage by IPC's residential customers in Oregon. The OPUC declines this recommendation in the Order, stating that IPC's tiered rate structure should first be reviewed in connection with the review of IPC's seasonal rates.
3. The Stipulation recommends increasing IPC's customer service charge to \$8.00 per month. This recommendation is adopted in the Order.
4. The Stipulation's rate spread provisions recommend increasing IPC's irrigation rates to 75% of the irrigators' cost of service. CUB requested that IPC's irrigation rates be reviewed on a regular basis, as a part of IPC's Annual Power Cost Update and Power Cost Adjustment Mechanism proceedings, in order to eventually bring the irrigation rates up to the cost of service. The OPUC declines this request in the Order. The Order also states that IPC's proposed 27.96% irrigation rate increase under the Stipulation is reasonable.
5. IPC seeks to change its definition of "billing cycle" from "27 to 33 days" to "27 to 36 days", and this change is approved in the Order.

Certain statements contained in this Current Report on Form 8-K, including statements with respect to future earnings, ongoing operations, and financial conditions, are forward-looking statements within the meaning of federal securities laws. Although IDACORP and Idaho Power Company believe that the expectations and assumptions reflected in these forward-looking statements are reasonable, these statements involve a number of risks and uncertainties, and actual results may differ materially from the results discussed in the statements. Factors that

could cause actual results to differ materially from the forward-looking statements include: the effect of regulatory decisions by the Idaho Public Utilities Commission, the Oregon Public Utility Commission and the Federal Energy Regulatory Commission affecting our ability to recover costs and/or earn a reasonable rate of return including, but not limited to, the disallowance of costs that have been deferred; changes in and compliance with state and federal laws, policies and regulations including new interpretations by oversight bodies, which include the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Idaho Public Utilities Commission and the Oregon Public Utility Commission, of existing policies and regulations that affect the cost of compliance, investigations and audits, penalties and costs of remediation that may or may not be recoverable through rates; changes in tax laws or related regulations or new interpretations of applicable law by the Internal Revenue Service or other taxing jurisdiction; litigation and regulatory proceedings, including those resulting from the energy situation in the western United States, and penalties and settlements that influence business and profitability; changes in and compliance with laws, regulations, and policies including changes in law and compliance with environmental, natural resources, endangered species and safety laws, regulations and policies and the adoption of laws and regulations addressing greenhouse gas emissions, global climate change, and energy policies; global climate change and regional weather variations affecting customer demand and hydroelectric generation; over-appropriation of surface and groundwater in the Snake River Basin resulting in reduced generation at hydroelectric facilities; construction of power generation, transmission and distribution facilities, including an inability to obtain required governmental permits and approvals, rights-of-way and siting, and risks related to contracting, construction and start-up; operation of power generating facilities including performance below expected levels, breakdown or failure of equipment, availability of transmission and fuel supply; changes in operating expenses and capital expenditures, including costs and availability of materials, fuel and commodities; blackouts or other disruptions of Idaho Power Company's transmission system or the western interconnected transmission system; population growth rates and other demographic patterns; market prices and demand for energy, including structural market changes; increases in uncollectible customer receivables; fluctuations in sources and uses of cash; results of financing efforts, including the ability to obtain financing or refinance existing debt when necessary or on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets and other economic conditions; actions by credit rating agencies, including changes in rating criteria and new interpretations of existing criteria; changes in interest rates or rates of inflation; performance of the stock market, interest rates, credit spreads and other financial market conditions, as well as changes in government regulations, which affect the amount and timing of required contributions to pension plans and the reported costs of providing pension and other postretirement benefits; increases in health care costs and the resulting effect on medical benefits paid for employees; increasing costs of insurance, changes in coverage terms and the ability to obtain insurance; homeland security, acts of war or terrorism; natural disasters and other natural risks, such as earthquake, flood, drought, lightning, wind and fire; adoption of or changes in critical accounting policies or estimates; and new accounting or Securities and Exchange Commission requirements, or new interpretation or application of existing requirements. Any such forward-looking statements should be considered in light of such factors and others noted in the companies' Annual Report on Form 10-K for the year ended December 31, 2009, and other reports on file with the Securities and Exchange Commission. Any forward-looking statement

speaks only as of the date on which such statement is made. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Item 9.01 Financial Statements and Exhibits

(d) Exhibits.

Number	Description
99.1	Order of the Public Utility Commission of Oregon dated February 24, 2010, in UE 213.
99.2	Stipulation, dated December 17, 2009, filed with the Public Utility Commission of Oregon in UE 213
10.1	Exhibit A to the IDACORP, Inc. Executive Incentive Plan, as amended February 26, 2010
10.2	IDACORP, Inc. Executive Incentive Plan NEO 2010 Award Opportunity Chart

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned hereunto duly authorized.

Dated: March 4, 2010

IDACORP, Inc.

By: /s/ Rex Blackburn
Rex Blackburn
Senior Vice President and
General Counsel

IDAHO POWER COMPANY

By: /s/ Rex Blackburn
Rex Blackburn
Senior Vice President and
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INDEX TO EXHIBITS

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EXHIBIT A

IDACORP Executive Incentive Plan 2010 Goals

HOW THE PLAN WORKS

The Plan consists of a combination of Operational and Customer Service goals for Idaho Power Company and Net Income targets for IDACORP. The intent of the Plan is to focus on key areas management can impact while maintaining a means of additional profit sharing should Net Income exceed expected performance.

The weightings for the two areas are as follows:

- Operational/Customer Service Goals – 30%
- IDACORP Consolidated Net Income – 70%

The total payout will be based on predetermined participation levels approved by the Board. The amount of incentive to be awarded each participant will be calculated by multiplying the approved incentive percentage by the combined multiplier times the base salary.

I. Operational/Customer Service Goals

A. Customer Satisfaction

The Customer Relationship Index (CRI) details the company's performance through the eyes of the customer and is based on a rolling 4-quarter average for the period beginning January 1, 2010 through December 31, 2010. The index consists of 5 specific questions asked of our customers by an independent survey company and addresses issues such as overall satisfaction, quality, value, advocacy and loyalty. The CRI goal for 2010 is as follows:

Performance Level	CRI Goal	Qualifying Multiplier
Threshold	%	7.5%
Target	%	15%
Maximum	%	30%

B. Network Reliability

This goal will be measured using the number of interruptions greater than 5 minutes in duration experienced by Small and Large General Service Customers ("Customers"). In addition to the required performance levels below, this metric contains a hurdle of no

more than 10% of Customers subjected to more than 6 interruptions. If this hurdle is not passed, the payout for the Network Reliability goal will be zero.

Performance Level	Interruptions	Qualifying Multiplier
Threshold		7.5%
Target		15%
Maximum		30%

II. IDACORP Consolidated Net Income, As Adjusted

Performance Level	IDACORP Consolidated Net Income	Qualifying Multiplier
Threshold	\$	35%
Target	\$	70%
Maximum	\$	140%

IDACORP Consolidated Net Income, as Adjusted, is defined as net income attributable to IDACORP, Inc., as reported on the audited consolidated IDACORP income statement for 2010, as adjusted (i) by subtracting from such number ___ percent of the amount of net tax benefits recorded in 2010 that result from (x) _____, (y) _____ and (z) accelerated amortization of accumulated deferred investment tax credits, to the extent such amounts combined exceed \$_____, and (ii) by disregarding the effect, if any, on such net tax benefit reduction, of the obligation of Idaho Power Company to share with its Idaho customers, as provided in Idaho Public Utilities Commission Order No. 30978, dated January 13, 2010, earnings in excess of a 10.5 percent return on equity.

IDACORP, Inc.
Executive Incentive Plan
NEO 2010 Award Opportunity Chart

<u>Name</u>	<u>Title</u>	<u>Threshold (\$)</u>	<u>Target (\$)</u>	<u>Maximum (\$)</u>
J. LaMont Keen	President and Chief Executive Officer, IDACORP and Idaho Power	\$ 248,000	\$ 496,000	\$ 992,000
Darrel T. Anderson	Executive Vice President – Administrative Services and Chief Financial Officer, IDACORP and Idaho Power	\$ 91,250	\$ 182,500	\$ 365,000
Daniel B. Minor	Executive Vice President - Operations, Idaho Power	\$ 85,000	\$ 170,000	\$ 340,000

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 213

In the Matter of

IDAHO POWER COMPANY

Request for a General Rate Revision.

ORDER

DISPOSITION: STIPULATION APPROVED IN PART

I. INTRODUCTION

This order addresses Idaho Power Company's (Idaho Power or the Company) request for a general rate revision filed on July 31, 2009. In this order, we adopt the stipulation filed by the parties, with a few exceptions related to residential rate design. This order results in an increase of approximately \$5 million to Idaho Power's revenue requirement, an overall rate increase of approximately 15.4 percent.

II. BACKGROUND AND PROCEDURAL HISTORY

Idaho Power is an electric company and public utility in the State of Oregon within the meaning of ORS 757.005. The Company provides electric service to approximately 18,000 retail customers within the state, and is subject to the Commission's jurisdiction with respect to the prices and terms of electric service for Oregon retail customers.

On July 31, 2009, Idaho Power filed Advice No. 09-09, an application for revised tariff schedules. The Company originally requested an increase in its Oregon revenues of \$7.3 million, or an overall rate increase of 22.6 percent.¹ According to the Company, its request is driven by two key drivers: new investment in electric plant, and differences between growth in Oregon jurisdictional expenses and growth in Oregon jurisdictional revenues. With respect to new investment, the Company asserts that it invested \$800 million in electric plant between 2003 to 2008, investments that have

¹ The revised tariffs proposed a 37.3 percent rate increase for the residential rate class, a 41.2 percent increase for the small general service class, an 11.2 percent increase for the large general service class, and a 44.7 percent increase for the irrigation class. Idaho Power filed supplemental testimony in support of its application on October 9, 2009.

resulted in a 12 percent increase in nameplate capacity since its last general rate case.² The Company also asserts that growth in Oregon expenses has outpaced growth in Oregon revenues by \$2.1 million since 2003, so the Company sought an additional \$2.1 million, or a 6.3 percent increase in Oregon revenues, to account for that difference.

On August 21, 2009, a prehearing conference was held and a procedural schedule was established. At its August 25, 2009, public meeting, the Commission suspended the proposed tariff revisions for a period of nine months pursuant to ORS 757.215.³

During the course of the proceeding, the following parties were granted leave to intervene as parties: the Oregon Industrial Customers of Idaho Power (OICIP); EP Minerals, LLC; and Portland General Electric Company (PGE). The Citizens' Utility Board of Oregon (CUB) intervened in the proceeding as a matter of right under ORS 774.180.

A public comment hearing was held in Ontario, Oregon, on September 29, 2009. Numerous customers appeared at the public hearing to object to the proposed rate increase. The Commission also received dozens of comments objecting to the proposed residential and irrigation rate increases.

Settlement conferences among the active parties⁴ took place on November 4 and 5, 2009. On December 17, 2009, the parties filed a stipulation (the Stipulation) addressing the issues in this docket. Although all parties signed the Stipulation, two parties reserved the right to object to specific portions of the agreement: CUB reserved the right to object to the stipulated design for residential rates, and OICIP expressed concerns about Idaho Power's Schedule 19 service quality. On January 19, 2010, CUB and OICIP filed objections with supporting testimony. Staff and Idaho Power filed joint reply testimony on January 26, 2010.

On January 29, 2010, the parties were asked to address whether OICIP's objections fell within the scope of this general rate proceeding.⁵ On February 2, 2010, OICIP agreed to remove its service quality issue from this proceeding and pursue it in a separate docket. As a result, the only formal objection to the Stipulation remaining in this docket is CUB's objection to the stipulated residential rate design. No party requested a hearing on CUB's contested issues, and the parties filed simultaneous briefs on February 3, 2010.

² See Idaho Power/100, Said/11. Idaho Power's last general rate case was filed on September 21, 2004. See Order No. 05-871, Docket UE 167 (July 28, 2005).

³ See Order No. 09-150.

⁴ PGE intervened in this docket but did not actively participate in the proceedings. References to the "parties" hereinafter refer only to the active parties.

⁵ See January 29, 2010, ruling requesting briefing.

III. DISCUSSION

We begin with an overview of the Stipulation, and then discuss contested issues.

A. Overview of the Stipulation

The Stipulation addresses all issues in this docket. If approved, it would reduce Idaho Power's proposed increase in test period revenue requirement from \$7.3 million, or 22.6 percent, to approximately \$5 million, or 15.4 percent.⁶

1. *Rate of Return and Taxes in Rates*

The Stipulation sets Idaho Power's return on equity (ROE) at 10.175 percent, and its overall rate of return at 8.061 percent. Under the Stipulation, the individual components of the assumed capital structure are as follows:

Capital Component	Capitalization	Cost	Weighted Cost
Long-Term Debt	50.20%	5.964%	2.994%
Preferred Stock	0.00%		
Common Equity	49.80%	10.175%	5.067%
TOTAL	100.00%		8.061%

The parties note that the stipulated rate of return represents a reduction in the Company's original request of 8.68 percent. It also represents an increase in the Company's currently authorized rate of return of 7.83 percent.

2. *Advanced Metering Infrastructure Communication Equipment*

The parties agree that capital expense associated with communication equipment acquired to implement the Company's Advanced Metering Infrastructure (AMI) system should be removed from this docket. This equipment has not yet been implemented in Idaho Power's Oregon jurisdiction. The Company will make a request to recover any prudently incurred investment in the future.⁷

3. *Net Power Supply Expense*

The Stipulation explains that the Company's filed case included a level of net power supply expense (NPSE) equivalent to that which is currently reflected in base rates, plus the October portion of the Company's Annual Power Cost Update (APCU) rate that became effective June 1, 2009.⁸ The parties agree that because the NPSE in that

⁶ Exhibit A to the Stipulation summarizes the stipulated adjustments to Idaho Power's Oregon-allocated results of operations. The parties to the Stipulation seek a rate effective date of March 1, 2010.

⁷ The parties also recognized that Idaho Power might receive federal funds under the American Reinvestment and Recovery Act to subsidize additional smart-grid technologies. In the event such funds are received, they will be used as an offset to investment, reducing the net rate base upon which future returns will be determined.

⁸ See, *In re Idaho Power Co.*, Docket UE 203, Order No. 09-186 (May 26, 2009).

docket was calculated using an April 2009 through March 2010 test period, it is appropriate to adjust the level of NPSE in this case to align with the 2009 calendar-year period. The parties agree that, on a going forward basis, the level of net power supply expense recovery included in the Company's base rates is \$10.94 per MWh, and that rate will become the base from which future APCU rates will be determined.

4. *Pension Expense*

Idaho Power's initial filing included no pension expenses. On October 20, 2009, the Company filed an application with the Commission requesting permission to account for pension expenses on a cash basis as opposed to an accrual basis, with the goal of recovering such expenses at some point in the future.

Under the Stipulation, Idaho Power would continue to account for pension expense on an accrual basis, a practice consistent with Statement of Financial Accounting Standards (SFAS) 87. The parties acknowledge that it is not practicable for Idaho Power to account for the difference in capitalized labor charges between jurisdictions with a fixed asset system, but state that Idaho Power has historically capitalized a portion of its labor costs, including SFAS 87 expense. In order to simulate the historic accounting without creating an undue burden on the Company, the Stipulation would allow Idaho Power to record the capital portion of its SFAS 87 expense as a regulatory asset to be amortized in a manner consistent with the depreciation of electric plant in service and revised by the Commission for inclusion in rates in a subsequent rate proceeding. The capital portion of pension expense in the fixed-asset system would be removed from net plant to prevent double recovery of pension expenses.

The parties further agree that the stipulated revenue requirement adopted in this rate case includes an SFAS 87 pension expense. Going forward, the parties agree the Commission should recognize both a regulatory asset associated with the capital portion of pension expense and the non-capital pension expense component when determining the Company's revenue requirement. If this provision is adopted, the Company agrees to withdraw its request to account for its pension expense on a cash basis.

5. *Marginal Cost Methodology*

The parties agree that the Company's marginal-cost approach to allocating costs is appropriate and should be adopted with one exception: at this time, transmission-related revenue requirement should be classified as 75 percent demand-related and 25 percent energy-related for the purpose of allocation to customer classes.

6. *Functionalization of Production Costs*

Idaho Power has historically separated its functionalized, embedded production costs into energy and demand components prior to their allocation. Instead of this approach, the parties agree that the functionalized production revenue requirement should be allocated directly, on the basis of each schedule's combined shares of marginal demand and energy costs.

7. Revenue Spread

The parties agree to implement Staff’s proposed changes to the Company’s rate spread, shown on Exhibit B to the Stipulation. This rate spread reduces the proportion of revenue requirement Idaho Power originally proposed to allocate to Residential Service, Small General Service, Large General Service-Secondary Voltage Level, and Agricultural Irrigation Service. The Company’s remaining customer classes receive a larger allocation of revenue requirement than originally proposed, except Large Power Service-Transmission Voltage Level and Area Lighting Service, which continue to receive no increase.

8. Rate Design

Idaho Power’s proposed rate design included seasonally differentiated rates for residential customers. With the exception of CUB, the parties agree that Idaho Power’s proposed rate design should be modified in the following manner:

- a. The residential service charge should be increased to only \$8.00 per month, rather than Idaho Power’s proposed \$10.00 per month.⁹
- b. The upper end of the first residential usage block should be increased to 1,000 kWh, rather than Idaho Power’s proposed 800 kWh, with the rate charge for the first block remaining the same throughout the year.¹⁰
- c. The Small General Service (Schedule 7) energy rate inversion point should be elevated from 300 kWh to 500 kWh.

9. Other Provisions

As part of the Stipulation, Idaho Power agrees to make changes to a number of its Oregon rules. The Company also makes various commitments to Schedule 19 customers.

With the exception of CUB’s objections to the stipulated design for residential rates, the parties agree that the Stipulation results in rates that are fair, just, and reasonable. The parties agree that no provision of the Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified therein.

B. Objections to the Stipulation

In this section, we address CUB’s objections to the stipulated residential rate design and briefly address irrigation rates. Although all active parties signed the Stipulation, CUB reserved the right to object to the stipulated design for residential rates, and the testimony and briefing supporting the Stipulation on the contested issues was

⁹ The residential service charge is currently \$5.25.

¹⁰ The upper end of the first residential usage block is currently 300 kWh.

filed by Idaho Power and Staff. For purposes of this section, Idaho Power and Staff will be referred to as the “Joint Parties.”

1. Legal Standard

The Commission has the broad powers to set just and reasonable rates.¹¹ As with any rate increase, Idaho Power bears the burden to show that a proposed rate change is just and reasonable.¹² When considering a stipulation, we have the statutory duty to make an independent judgment as to whether any given settlement constitutes a reasonable resolution of the issues. We may accept a non-unanimous settlement agreement so long as we make an independent finding, supported by substantial competent evidence in the record as a whole, that the settlement will establish just and reasonable rates.¹³

2. Residential Rate Design

a. Seasonal Rates

i. Parties' Positions

CUB challenges the Company's proposed seasonal rate design for Idaho Power's residential customers. Under the proposed design, residential customers using more than 1,000 kWh per month would pay higher rates in the summer, when overall customer usage of the Company's system peaks. CUB asserts that the proposed rates may be confusing to customers, and there is no evidence to show that imposing the proposed price signals on winter-peaking residential customers will actually be effective in reducing peak energy consumption. For residential customers, CUB believes that the development of energy efficiency programs should be a stronger focus than price signals, and CUB questions the effectiveness of Idaho Power's energy efficiency programs. CUB also asserts that it is inconsistent to use seasonal rates to send price signals to residential customers during the summer peak, while simultaneously protecting summer-peaking irrigation customers from receiving accurate price signals by capping irrigators' rates at 75 percent of their cost of service.

Staff and Idaho Power believe seasonal rates for residential customers should be adopted because they serve several purposes: they move the energy rate closer to the marginal cost of providing energy in the summer and non-summer months, encourage energy efficiency for the residential customer class year-round, and facilitate consistency throughout the Company's service territory by aligning the residential rate design in both the Company's Idaho and Oregon jurisdictions.¹⁴ Staff and Idaho Power assert that the seasonal rates, as designed, will discourage excessive use of refrigerated

¹¹ See ORS 756.040 (Commission shall protect customers and the public from unjust and unreasonable exactions and practices and obtain for them adequate service at fair and reasonable rates).

¹² See ORS 757.210. See also, *In re PacifiCorp*, Docket UM 995, Order No. 02-469 at 4 (July 18, 2002).

¹³ See, e.g., Order No. 02-469 at 75 (“Where some parties oppose a stipulation, * * * we will adopt a stipulation only if competent evidence supports it.”).

¹⁴ See Staff/100, Compton/7-19; Idaho Power/900, Waites/5.

air conditioning in the summer, when power is most expensive for the Company, without being overly burdensome to customers.

ii. Resolution

Idaho Power sought to implement seasonal rates for residential customers in its last general rate case. We declined to adopt seasonal rates in that docket, finding that Idaho Power failed to demonstrate that residential customers would be likely to respond to higher summer bills in the manner the Company predicted.¹⁵

Once again, we decline to adopt the seasonal rates proposed by Idaho Power. We make no findings in this docket about whether well designed seasonal rates may be appropriate for the Oregon residential customers of Idaho Power. We recently declined to adopt a new rate design proposal in Portland General Electric Company's general rate case, choosing instead to open a separate proceeding to consider policy issues, and we do the same here.¹⁶

b. Tiered Residential Rates

i. Parties' Positions

Idaho Power's residential customers currently have a two-tier inverted block structure in which customers pay one energy charge for the first 300 kWh of energy, and a higher charge for all energy used thereafter. The Stipulation proposes moving the breakpoint for the second tier from 300 kWh to 1,000 kWh.

CUB asks the Commission to leave the Company's tiered rates at their current levels. CUB states that it would ordinarily agree to the higher 1,000 kWh price inversion point, but the magnitude of this rate increase makes it more appropriate to retain the current blocks in order to more evenly spread the increase among residential customers. Keeping the existing block structure, CUB asserts, will help avoid rate shock at higher levels of usage.

Idaho Power explains that modifying the existing block structure will better meet the purpose of the tiered blocks. The Company asserts that the first energy block is intended to cover a majority of customers' basic electric usage, such as usage from lighting and home appliances, while the second block is intended to cover more discretionary usage.¹⁷ The Company's studies show that the average monthly residential

¹⁵ *In re Idaho Power Co.*, UE 167, Order No. 05-871 at 12 (July 28, 2005).

¹⁶ *See, In re Portland General Electric Co.*, Docket UE 197, Order No. 08-585 (Dec. 15, 2008) (declining to adopt a new rate design and ordering the opening of a policy docket to examine relevant issues). The purpose of the policy docket will be to consider guidelines for deciding whether to adopt time-differentiated rates and for the design of such rates, if warranted. For example, an important issue is the extent to which customers' ability to respond to seasonal rates, or other time-differentiated rates, should be a condition for adopting such rates. In connection with its objections to seasonal rates, CUB also asked the Commission to open an investigation into Idaho Power's energy efficiency programs. We decline to open such an investigation at this time

¹⁷ Idaho Power/900, Waites/6.

usage for 2008 was 1,247 kWh, making the 300 kWh breakpoint too low.¹⁸ In its initial filing, Idaho Power sought to move the price inversion point to 800 kWh, which would capture about 60 percent of average energy use at the lower rate. As part of the Stipulation, the price inversion point was moved even higher, to 1,000 kWh.

According to Staff,

[A]lgebraically, and for a fixed revenue target for the residential schedule, the fewer the number of kWh's that are assessed the higher, tail-block price, the higher that price can be without leading to excess class revenues or without requiring the customer charge and/or the initial block's rate to be lower than desired. This feature is important in the current case because the summer costs are so much higher than the yearly average.¹⁹

ii. Resolution

While we understand the rationale for increasing the size of the first inverted block, under the circumstances of this case we will retain Idaho Power's current rate design with a 300 kWh first tiered block. As noted above, we have declined the Joint Parties' proposal to adopt seasonal rates, concluding instead to first conduct a more thorough examination of residential rate design issues to obtain more information. Because that investigation may yield useful data relevant to the proper design of tiered rates, we similarly decline the Joint Parties' proposal here.

c. Customer Service Charge

i. Parties' Positions

CUB challenges the stipulated increase in the residential customer service charge. Idaho Power's fixed charge for residential customers is currently \$5.25 per month. Idaho Power originally proposed increasing this charge to \$10.00. In the Stipulation, the Joint Parties agree to increase the service charge to \$8.00.

CUB asks the Commission to limit the increase in the basic service charge to \$6.50, arguing that increasing the base rate will disproportionately impact customers with low monthly usage. Moreover, CUB argues, if the Commission wishes to increase the price signals received by customers, it should not move rates from variable to base portions of rates.

Idaho Power explains that its customer service charge is currently too low. The charge is intended to recover costs that do not vary with the amount of energy or capacity used, but the service charge has historically undercollected costs. Increasing the charge would move individual rate components closer to the cost of providing electric service. The Joint Parties agree that \$8.00 represents customer-related costs that are

¹⁸ Idaho Power/900, Waites/7.

¹⁹ Staff/300, Compton/26-27.

appropriately included in the basic customer charge, consistent with Commission precedent.

ii. Resolution

We find the stipulated resolution of the residential customer basic charge issue to be reasonable. CUB does not contest the Joint Parties' assertion that an \$8.00 basic charge fairly represents customer-related costs. As a general matter, moving customer-related costs into fixed charges is consistent with Commission precedent and we see no reason to deviate from that precedent here.

d. Reducing Subsidies to Irrigation Customers

i. Parties' Positions

CUB has stipulated to the rate spread portion of the Stipulation, which moves certain customer classes closer to their actual cost of service. Not all customers are moved to full cost of service, however. Under the stipulated rate spread, the rate increase for the irrigation class is limited to 75 percent of the irrigators' cost of service.²⁰ The parties agreed to cap the irrigators' rate at this level to prevent irrigation customers from suffering rate shock.

CUB states it is willing to agree to the stipulated rate spread because all customer classes should be protected from rate shock. Nevertheless, CUB feels strongly that the subsidies for irrigators should be removed over time. Because Idaho Power's last general rate case was filed in 2004, CUB is concerned that the Company will not file general rate cases on a regular basis. As a result, it could take an unreasonable amount of time for irrigation rates to reflect irrigators' actual cost of service. CUB therefore asks the Commission to gradually eliminate irrigation subsidies through rate spread adjustments in Idaho Power's APCU and Power Cost Adjustment Mechanism (PCAM) dockets, which occur on an annual basis.

Idaho Power and Staff disagree with this recommendation. Idaho Power argues that general rate cases are the appropriate venues for addressing cost allocation and inter-class subsidy issues because they involve full cost-of-service and marginal cost analyses, as well as wide public participation. APCU and PCAM proceedings, by contrast, are single issue, automatic adjustment clause mechanisms intended for other purposes. Staff believes the Commission should look at all available opportunities to eliminate subsidies for the irrigation class over time, but does not recommend that the Commission explicitly order any such changes to occur in the APCU and PCAM dockets.

ii. Resolution

Given the limited issues involved in PCAM and APCU dockets, we decline at this time to order rate allocation issues to be addressed in those specific

²⁰ Under the stipulated rate spread, most other rate classes, including the residential class, will have rates that reflect approximately 103 percent of their cost of service.

dockets. We agree with Staff, however, that the Commission should look at available opportunities to move Idaho Power customers closer to their cost of service.

e. Length of Billing Cycles

i. Parties' Positions

Idaho Power seeks to change its definition of "billing cycle" from "27 to 33 days" to "27 to 36 days." CUB argues this rule change has the potential to be harmful to customers in a tiered rate structure, because usage in the longer billing cycle will be billed at a higher rate, particularly if seasonal rates are adopted.

The Joint Parties assert that any issues with the new definition of "billing cycle" can be remedied by a prorating protocol. In any case, only 0.22 percent of customers would receive bills with 34-36 day billing periods.

ii. Resolution

We find the proposed rule change to be reasonable. The new rule would make Idaho Power's definition of "billing cycle" consistent in both Oregon and Idaho, and would appear to have little impact on customers, particularly since we have declined at this time to adopt seasonal rates or modifications to Idaho Power's existing inverted-block structure.

3. Irrigation Rates

As noted above, the Commission received robust public comment objecting to Idaho Power's proposed rate increase, particularly with respect to the proposal to increase irrigation rates by 44.7 percent. At the September 29, 2009, public comment meeting in Ontario, as well as in written letters and emails, customers expressed dissatisfaction with the proposed increase and explained the difficulty of paying electric bills during this difficult economic period.

We have carefully reviewed the rate increase in this docket, and the irrigation rates in particular, and find the proposed rate increases for all customer classes to be appropriate. Given that the Company has waited several years to seek recovery of new investment in rates, we recognize that the rate increases imposed by this order are significant. While we would prefer not to impose any rate increase on customers during difficult economic times, Idaho Power is entitled to recover in rates the costs of property currently being used to serve customers. In recognition of the potential rate shock that would be caused by a 44.7 percent increase in irrigation rates, however, the parties have agreed to limit the increase in irrigation rates to 75 percent of the cost of serving the irrigation class. This limits the increase in irrigation rates to 27.96 percent. We find this solution to be a reasonable one.

IV. CONCLUSION

With the exception of the residential rate design issues addressed above, we find that the Stipulation, set forth in Appendix A to this order, will result in rates that are fair, just, and reasonable. With the exception of the aforementioned issues, the Stipulation is adopted.

V. ORDER

IT IS ORDERED that:

1. Advice No. 09-09 is permanently suspended.
2. With the exception of residential rate design issues noted in this order, the Stipulation by and between the Idaho Power Company; Oregon Industrial Customers of Idaho Power; EP Minerals, LLC; and the Citizens' Utility Board is adopted.
3. Idaho Power Company must file new tariffs consistent with this order to be effective no earlier than March 1, 2010.

Made, entered, and effective _____.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

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.

1 **BACKGROUND**

2 1. On July 31, 2009, Idaho Power filed revised tariff sheets with the Public
3 Utility Commission of Oregon (“Commission”) that would result in a base price
4 increase of approximately \$7.3 million or 22.6 percent on an Oregon jurisdictional
5 basis. The tariff sheets were to be effective on August 31, 2009. Idaho Power’s filing
6 was based on a 2009 calendar year test period.

7 2. At the public meeting on August 25, 2009 the Commission suspended
8 the Company’s revised tariff sheets for a period of nine months. Pursuant to
9 Administrative Law Judge Lisa Hardie’s Prehearing Conference Memorandum of
10 August 25, 2009, the Parties convened a settlement conference on November 4-5,
11 2009. The settlement conference was noticed and all parties attended.²¹

12 3. As a result of the settlement conference, the Parties have reached a
13 settlement in this case resolving all issues in the case, except for the issues of
14 Residential Rate Design and service quality. CUB does not agree to the Parties’
15 resolution of the Residential Rate Design issue and OICIP has unresolved concerns
16 about Schedule 19 service quality.

17 4. The net effect of the Stipulation is to reduce Idaho Power’s proposed
18 increase in test period revenue requirement to approximately \$5 million, which will
19 result in an overall increase of approximately 15.4 percent. The parties agree to
20 request a schedule for the remaining procedures in the docket consistent with a rate
21 effective date of March 1, 2010, provided that such a schedule will allow CUB and
22 OICIP adequate time to prepare their respective testimony on Residential Rate
23 Design and service quality.

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²¹ EP Minerals did not attend as a separate entity but rather in its capacity as a member of OICIP.

1 **AGREEMENT**

2 5. Just and Reasonable Rates: The Parties agree, with the exception of
3 the issue of Residential Rate Design which is being disputed by CUB and service
4 quality which is being disputed by OICIP, to submit this Stipulation to the Commission
5 and request that the Commission approve the Stipulation as presented subject to
6 resolution of CUB's opposition to the Residential Rate Design issue and OICIP's
7 concerns regarding Schedule 19 service quality. The Parties agree that the
8 adjustments—and the rates resulting from their application—are fair just and
9 reasonable subject to OICIP's position on service quality discussed in paragraph 21
10 and CUB's position on Residential Rate Design discussed in paragraph 21.

11 6. Revenue Requirement: The Parties agree to a revenue requirement
12 increase of \$5 million in base rates on an Oregon jurisdictional basis, which
13 represents an increase of 15.4 percent from the current \$32.4 million Oregon
14 revenues. Exhibit A details the agreed-upon calculation of the 15.4 percent increase
15 in base rates based on resolution by the Parties of adjustments to the Company's
16 request. The Parties agree that the acceptance of these adjustments for the
17 purposes of settlement is not acceptance of any methodology underlying the various
18 adjustments, is not binding on Parties in future proceedings, and does not imply
19 agreement on the merits of the adjustments.

20 7. Rate of Return: The Parties agree that the Company's ROE should be
21 set at 10.175 percent and the Company's overall ROR should be set at 8.061
22 percent. The individual components in the assumed capital structure should be set
23 as shown in the table below:

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Financial Component	percent	Cost	Weighted Avg.
Long Term Cost of Debt	50.200	5.964 percent	2.994 percent
Preferred Stock	00.000		
Common Stock Equity	49.800	10.175 percent	5.067 percent
Total	100.000		8.061 percent

8. AMI Communication Equipment: The Parties agree that it is appropriate to remove from the case capital expense associated with communication equipment acquired to implement the Company's Advanced Metering Infrastructure ("AMI") system, given that AMI has not yet been implemented in the Company's Oregon jurisdiction. However, the Parties recognize that the Company will in the future make a request to recover any prudently-incurred investment in such equipment once AMI is implemented in Oregon. On a related topic, the Parties recognize that Idaho Power may receive federal funds under the American Reinvestment and Recovery Act ("ARRA") that will be used to subsidize certain additional Smart Grid technologies. In the event such funds are received, those amounts received will be utilized as an offset to investments reducing the net rate base upon which future returns will be determined.

9. Net Power Supply Expense: The Company's filed case included a level of net power supply expense ("NPSE") equivalent to that which is currently reflected in base rates plus the October portion of the Annual Power Cost Update ("APCU") rate that became effective June 1, 2009 (Order No. 09-186, Docket No. UE 203). Because the NPSE approved by Order No. 09-186 was calculated according to a April 2009 through March 2010 test period, Parties agree that it is appropriate to adjust the level of NPSE in this case to align with the 2009 calendar-year test period. Further the Parties agree that, on a going forward basis, the level of net power supply

1 expense recovery included in the Company's base rates is \$10.94 per megawatt-
2 hour and that the \$10.94 rate will become the base from which future APCU rates will
3 be determined.

4 10. Pension Expense: The Company's filed case did not include any
5 expense related to pension. On October 20, 2009, the Company filed an application
6 with the Commission requesting permission to account for pension expenses on a
7 cash basis as opposed to accrual basis, with the plan to recover such expenses at
8 some point in the future. As a result of settlement discussions the Parties agree that
9 the Company should continue to account for pension expense on an accrual basis,
10 consistent with SFAS 87. The Parties acknowledge that it is not practicable for Idaho
11 Power to account for differences in capitalized labor charges between jurisdictions
12 within a fixed asset system. However, Idaho Power has historically capitalized a
13 portion of its labor costs, including SFAS 87 expense. In order to simulate the historic
14 accounting without creating undue burden, the Parties agree that the Company
15 should be allowed to record the capital portion of its SFAS 87 expense as a
16 regulatory asset. The regulatory asset will be amortized in a manner consistent with
17 the depreciation of electric plant in service and will be reviewed by the Commission
18 for inclusion in rates in a subsequent rate proceeding. The capital portion of pension
19 expense in the fixed-asset system will be removed from net plant to prevent any
20 double recovery of pension expenses. Further the Parties agree that the stipulated
21 revenue requirement adopted by the Commission in this rate case includes an SFAS
22 87 pension expense. The Parties agree that, on a going forward basis, the
23 Commission should recognize both a regulatory asset associated with the capital
24 portion of pension expense and the non-capital pension expense component when
25 determining the Company's revenue requirement. If the Commission adopts this
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1 provision, the Company agrees to withdraw its request to move to a cash basis
2 account for pension expense.

3 11. Marginal Cost Methodology: The Parties agree that the Company's
4 marginal cost approach to allocating costs is appropriate and should be adopted with
5 one exception: The Parties agree that at this time, transmission-related revenue
6 requirement should be classified as 75 percent demand-related and 25 percent
7 energy-related for the purpose of allocation to customer classes.

8 12. Functionalization of Production Costs: Idaho Power has historically
9 separated its functionalized, embedded production costs into energy and demand
10 components prior to their allocation. Instead, the Parties agree that the
11 functionalized production revenue requirement should be allocated directly and on
12 the basis of each schedule's combined shares of marginal demand and energy costs.

13 13. Revenue Spread: Except to the extent that it is inconsistent with
14 paragraph 11 regarding allocation of the transmission-related revenue requirement to
15 customer classes, the Parties agree to implement Staff's proposed changes to the
16 Company's rate spread, as shown on Exhibit B. The agreed upon approach to
17 revenue spread results in a reduction in the proportion of revenue requirement
18 allocated to Residential Service, Small General Service, Large General Service-
19 Secondary Voltage Level and Agricultural Irrigation Service. The remainder of the
20 Company's customer classes receive a larger allocation of revenue requirement with
21 the exception of Large Power Service-Transmission Voltage Level and Area Lighting
22 Service which continue to receive no increase.

23 14. Rate Design: The Parties, with the exception of CUB, agree that Idaho
24 Power's proposed rate design should be adopted as modified below:

25 a. The residential service charge should be increased to \$8.00 a month as
26 opposed to the \$10.00 a month originally proposed by the Company;

1 b. The upper end of the first residential usage block should be increased from
2 800 kWh to 1000 kWh, with the rate charge for the first block remaining the
3 same throughout the year.

4 c. The Small General Service (Schedule 7) energy rate inversion point should
5 be elevated from 300 kWh to 500 kWh.

6 CUB intends to file testimony in opposition to the residential portion of this
7 Rate Design.

8 15. Rule F Modifications: Idaho Power agrees to withdraw its proposal to
9 implement the (a) Service Establishment Charge found in proposed Rule F, section
10 (1); and (b) Continuous Service Reversion Charge, found in proposed Rule F, section
11 (2).

12 16. Rule H: Idaho Power agrees that by March 31, 2010, it will file revisions
13 to Rule H, New Service Attachments and Distribution Line Installations or Alterations.

14 17. Rule K: Idaho Power agrees to withdraw its proposed additional
15 language to Rule K, paragraph 4, and address any addition of the proposed
16 language at future workshops to be held with Schedule 19 customers and the
17 Oregon Commission Staff.

18 18. EnerNoc Program: In 2010 the Company plans to evaluate the first
19 year operational results of the EnerNoc program it has conducted in its Idaho
20 jurisdiction. Idaho Power commits to sharing the results of this review (subject to
21 confidentiality concerns) with Schedule 19 customers.. The Company agrees also to
22 file a third-party-operated, incentive-based, peak demand reduction program (such
23 as the EnerNoc contract), which will be available to Schedule 19 customers in
24 Oregon during the 2010 peaking season.

25 19. Diesel Standby: The Company commits to include in its 2009
26 Integrated Resource Plan 1) a determination of the cost and viability of an incentive-

1 based standby generation program targeted toward Large Power Service (Schedule
2 19) customers and 2) a description of the Company's intent to develop such a
3 program through a collaborative approach involving Schedule 19 customers. The
4 Company commits to making this program available to its Schedule 19 customers in
5 Oregon provided that it finds that the program will be cost-effective and in the best
6 interests of its customers.

7 20. CUB's Position: CUB agrees with and supports all aspects of this
8 Stipulation except that CUB does not agree with the stipulated Residential Rate
9 Design. CUB intends to challenge this aspect of the Stipulation.

10 21. OICIP's Position: OICIP agrees with and supports all aspects of this
11 Stipulation except that OICIP will request that the Commission in this case address
12 Schedule 19 service quality.

13 22. This Stipulation will be offered into the record of this proceeding as
14 evidence pursuant to OAR 860-014-0085. With the exception of CUB's opposition to
15 Residential Rate Design and OICIP's position with respect to Schedule 19 service
16 quality standards, the Parties agree to support this Stipulation throughout this
17 proceeding and any appeal (if necessary), provide witnesses to sponsor this
18 Stipulation at the hearing and recommend that the Commission issue an order
19 adopting the settlements contained herein. The two exceptions are that the Parties
20 acknowledge that CUB opposes the current Residential Rate Design settlement
21 proposal and that CUB will submit testimony, on January 19, 2010, in opposition to
22 the Residential Rate Design portion of the Stipulation. The Parties also acknowledge
23 that OICIP will challenge the Company's Schedule 19 service quality and will submit
24 testimony, on January 19, 2010, to address its concerns.

25 23. The Parties have negotiated this Stipulation as an integrated document.
26 If the Commission rejects all or any material portion of this Stipulation or imposes

1 additional material conditions in approving this Stipulation, any party disadvantaged
2 by such action shall have the rights provided in OAR 860-014-0085 and shall be
3 entitled to seek reconsideration or appeal of the Commission's order.

4 24. By entering into this Stipulation, no Party shall be deemed to have
5 approved, admitted, or consented to the facts, principles, methods, or theories
6 employed by any other Party in arriving at the terms of the Stipulation, other than
7 those specifically identified in the body of this Stipulation. No party shall be deemed
8 to have agreed that any provision of this Stipulation is appropriate for resolving
9 issues in any other proceeding, except as specifically identified in this Stipulation.

10 25. This Stipulation may be executed in counterparts and each signed
11 counterpart shall constitute an original document.

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13 ***SIGNATURE PAGE FOLLOWS***
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IDAHO POWER COMPANY

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STAFF

IDAHO POWER

By: /s/ _____

By: /s/ _____

Date: _____

Date: _____

CITIZENS' UTILITY BOARD OF OREGON

OREGON INDUSTRIAL CUSTOMERS
OF IDAHO POWER

By: /s/ _____

By: /s/ _____

Date: _____

Date: _____

EP MINERALS LLC

By: /s/ _____

Date: _____