ORDER NO. 10-064
ENTERED 02/24/10

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 resulted in a 12 percent increase in nameplate capacity since its last general rate case.[2]

[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.
[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).

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 parties[4] 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.

III. DISCUSSION

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

---

[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.

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 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

---

[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).

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 FEB 24 2010.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
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 213

IN THE MATTER OF IDAHO POWER COMPANY'S FILING OF REVISED TARIFF SCHEDULES FOR ELECTRIC SERVICE IN OREGON.	**STIPULATION**

This Stipulation is entered into for the purposes of resolving the issues among the parties to this docket. This Stipulation fully resolves all issues in the docket except the issues of Residential Rate Design and service quality. All Parties except Citizens' Utility Board of Oregon ("CUB") agree upon Residential Rate Design. In addition, Oregon Industrial Customers of Idaho Power ("OICIP") has concerns about the Company's Schedule 19 service quality that are not addressed by the Stipulation. CUB objects only to the Residential Rate Design portions of this Stipulation and will file, on January 19, 2010, testimony only in opposition to the Residential Rate Design portion of the Stipulation. OICIP likewise will file, on January 19, 2010, testimony only regarding Schedule 19 service quality.

PARTIES

The parties to this Stipulation are Idaho Power Company ("Idaho Power" or "Company"), Staff of the Public Utility Commission of Oregon ("Staff"), OICIP, EP Minerals, and CUB (the "Parties"). The Parties constitute all parties to the docket, with the exception of Portland General Electric ("PGE") who did not actively participate in the docket.

BACKGROUND

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

2. At the public meeting on August 25, 2009 the Commission suspended the Company's revised tariff sheets for a period of nine months. Pursuant to Administrative Law Judge Lisa Hardie's Prehearing Conference Memorandum of August 25, 2009, the Parties convened a settlement conference on November 4-5, 2009. The settlement conference was noticed and all parties attended.[1]

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

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

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

AGREEMENT

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

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

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

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

8. <u>AMI Communication Equipment:</u> 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. <u>Net Power Supply Expense:</u> 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

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

10. Pension Expense: The Company's filed case did not include any expense related to pension. 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 accrual basis, with the plan to recover such expenses at some point in the future. As a result of settlement discussions the Parties agree that the Company should continue to account for pension expense on an accrual basis, consistent with SFAS 87. The Parties acknowledge that it is not practicable for Idaho Power to account for differences in capitalized labor charges between jurisdictions within a fixed asset system. However, Idaho Power has historically capitalized a portion of its labor costs, including SFAS 87 expense. In order to simulate the historic accounting without creating undue burden, the Parties agree that the Company should be allowed to record the capital portion of its SFAS 87 expense as a regulatory asset. The regulatory asset will be amortized in a manner consistent with the depreciation of electric plant in service and will be reviewed by the Commission 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 any double recovery of pension expenses. Further the Parties agree that the stipulated revenue requirement adopted by the Commission in this rate case includes an SFAS 87 pension expense. The Parties agree that, on a going forward basis, 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 the Commission adopts this

provision, the Company agrees to withdraw its request to move to a cash basis account for pension expense.

11. 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: The Parties agree that at this time, transmission-related revenue requirement should be classified as 75% demand-related and 25% energy-related for the purpose of allocation to customer classes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SIGNATURE PAGE FOLLOWS

STAFF

By: Mike [signature]

Date: 12/17/09

IDAHO POWER

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________

Date: ______________________

OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER

By: ______________________

Date: ______________________

EP MINERALS LLC

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

IDAHO POWER

By: ______________________

Date: 12-16-09

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________

Date: ______________________

OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER

By: ______________________

Date: ______________________

EP MINERALS LLC

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

IDAHO POWER

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________

Date: 16 Dec 2009

OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER

By: ______________________

Date: ______________________

EP MINERALS LLC

By: ______________________

Date: ______________________

STAFF

By: ______________________________

Date: ______________________________

IDAHO POWER

By: ______________________________

Date: ______________________________

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________________

Date: ______________________________

OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER

By: ______________________________

Date: 12/16/2009

EP MINERALS LLC

By: ______________________________

Date: ______________________________

STAFF	IDAHO POWER
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________
CITIZENS' UTILITY BOARD OF OREGON	OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________

EP MINERALS LLC

By: ______________________

Date: 12/16/09

IDAHO POWER COMPANY
Revenue Requirement Adjustments - Settlement
Twelve Months Ended December 31, 2009
($000)

Revenue Deficiency on the Company's Filed Results	$7,329
Rate of Return Adjustment	(1,125)
Rate Base Adjustments	
Transmission Plant	(6)
Distribution Plant	(7)
General Plant Communication Equipment	(33)
General Plant Adjustment	(97)
Plant Held for Future Use	(25)
Total Rate Base Adjustment	(168)
Expense Adjustments	
Wage & Salary Adjustment	($117)
FTE Adjustment	(163)
Bonus Adjustment	($75)
Meter Depreciation	(628)
Power Supply & Transmission Loss	(203)
A&G and O&M Adjustments	150
Total Expense Adjustment	($1,036)
Total Revenue Requirement Adjustment	(2,329)
Adjusted Change in Revenue Requirement	$5,000
Current Revenue	$32,434
Percent Increase	15.4%

ORDER NO. 10-064

Exhibit B/Staff

IDAHO POWER COMPANY
Marginal Cost Analysis 2009 – FINAL Settlement
Marginal Cost By Class - OREGON JURISDICTION
(2009 Dollars)

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) LG POWER TRANS (19-T)	(I) IRRIGATION SECONDARY (24-S)	(J) UNMETERED GEN SERVICE (40)	(K) MUNICIPAL ST LIGHT (41)	(L) TRAFFIC CONTROL (42)
1	*Normalized Sales (kWh)*	740,533,031	220,362,881	19,087,766	129,779,060	17,340,865	470,308	195,081,276	90,310,412	67,154,213	14,306	912,800	19,144
2	Current Revenue	$32,433,692	$11,262,377	$1,176,138	$6,331,332	$654,786	$98,625	$6,712,141	$3,243,600	$2,846,148	$772	$106,979	$794
3													
4	Generation Marginal Cost												
5	Generation Demand-Related	$5,368,907	$1,681,622	$160,628	$942,951	$119,727	$519	$1,078,999	$563,709	$819,581	$75	$995	$100
6	Generation Energy-Related	$46,251,305	$13,587,114	$1,187,823	$7,954,222	$1,055,870	$28,374	$11,838,944	$5,800,384	$4,741,513	$863	$55,044	$1,155
7	Generation Total	$51,620,212	$15,268,735	$1,348,451	$8,897,174	$1,175,597	$28,893	$12,917,943	$6,364,093	$5,561,094	$938	$56,039	$1,255
8	Transmission Marginal Cost												
9	Transmission Demand-Related (75%)	$14,714,881	$4,912,854	$433,698	$2,725,422	$348,347	$2,358	$3,117,028	$1,404,982	$1,765,148	$216	$4,540	$289
10	Transmission Energy-Related (25%)	$4,904,960	$1,459,585	$126,429	$859,599	$114,858	$3,115	$1,292,131	$598,176	$444,800	$95	$6,046	$127
11	Transmission Total	$19,619,842	$6,372,439	$560,127	$3,585,021	$463,205	$5,473	$4,409,159	$2,003,158	$2,209,948	$311	$10,586	$416
12	Distribution Marginal Cost												
13	Demand-Related	$9,658,948	$4,441,166	$280,793	$1,812,158	$171,415	$5,820	$1,102,323	$0	$1,833,817	$156	$11,191	$110
14	Customer-Related	$2,877,137	$1,831,719	$489,644	$230,216	$7,279	$0	$18,994	$6,595	$289,732	$261	$1,857	$838
15													
16	Total Functionized Revenue Requirement												
17	Generation	$20,407,194	$6,036,241	$533,088	$3,517,350	$464,753	$11,422	$5,106,895	$2,515,939	$2,198,486	$371	$22,154	$496
18	Transmission	$3,694,492	$1,199,955	$105,474	$675,073	$87,223	$1,031	$830,262	$377,202	$416,142	$58	$1,993	$78
19	Distribution												
20	Demand-Related	$10,306,242	$4,738,791	$299,610	$1,933,600	$182,902	$6,210	$1,176,195	$0	$1,956,711	$166	$11,941	$117
21	Customer-Related												
22	Allocated	$2,611,035	$1,662,306	$444,358	$208,924	$6,606	$0	$17,238	$5,985	$262,935	$237	$1,686	$760
23	Direct Assignment	$414,826	$190,712	$42,634	$18,964	$71	$58,699	$85	$30	$21,595	$43	$81,908	$85
24													
25	Total	$37,433,790	$13,828,005	$1,425,163	$6,353,911	$741,555	$77,361	$7,130,674	$2,899,156	$4,855,869	$876	$119,683	$1,537
26	Revenue Difficiency	$5,000,098	$2,565,628	$249,025	$22,579	$86,769	($21,264)	$418,533	($344,444)	$2,009,721	$104	$12,704	$743
27	% Increase Required	15.42%	22.78%	21.17%	0.36%	13.25%	-21.56%	6.24%	-10.62%	70.61%	13.41%	11.88%	93.60%
28													
29	Proposed Revenue Spread	$37,434,662	$14,224,869	$1,466,066	$6,536,268	$762,838	$98,625	$7,335,324	$3,243,600	$3,641,901	$901	$123,118	$1,153
30	% Increase Required	15.42%	26.30%	24.65%	3.24%	16.50%	0.00%	9.28%	0.00%	27.96%	16.67%	15.09%	45.20%
31	Cost of Service Index		102.87%	102.87%	102.87%	102.87%	127.49%	102.87%	111.88%	75.00%	102.87%	102.87%	75.00%
32	Average Mills Per kWh	50.55	64.55	76.81	50.36	43.99	209.70	37.60	35.92	54.23	62.96	134.88	60.22

APPENDIX A
PAGE 16 OF 16