ORDER NO. 10-022
ENTERED 01/26/10

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision.	ORDER

DISPOSITION: STIPULATIONS APPROVED

I. INTRODUCTION

This order addresses PacifiCorp, dba Pacific Power's (Pacific Power or the Company) request for a general rate revision filed with the Public Utility Commission of Oregon (Commission) on April 2, 2009. In this order, we adopt two stipulations: a contested revenue requirement stipulation, and an uncontested rate spread and rate design stipulation. These stipulations result in a 4.6 percent increase to Pacific Power's rates.

II. BACKGROUND AND PROCEDURAL HISTORY

Pacific Power is an electric company and public utility in the State of Oregon within the meaning of ORS 757.005, and is subject to the Commission's jurisdiction with respect to the prices and terms of electric service to its Oregon retail customers. The Company provides electric service to approximately 580,000 retail customers in Oregon.

On April 2, 2009, Pacific Power filed Advice No. 09-008, an application for revised tariff schedules. In its application, the Company requested a revenue increase of $92.1 million, or 9.1 percent overall.[1] Pacific Power stated that the primary driver for its rate request was new investment, including, among other things, the addition of two natural gas plants, three wind resources to serve customers, investment in transmission and distribution plant, and investment in hydroelectric plant to conform with various hydro relicensing agreements.[2]

[1] The revised tariffs proposed a 6.3 percent rate increase for the residential rate class, a 13.7 percent increase for the small non-residential class, a 13.7 percent increase for the large non-residential rate class, a 17.5 percent increase for the irrigation class, and a 17.5 percent increase for lighting and signal customers.
[2] Certain portions of the Company's testimony in support of its application will be discussed in more detail below.

At its April 21, 2009, public meeting, the Commission suspended the proposed tariff revisions for a period of nine months pursuant to ORS 757.215.[3] On April 21, 2009, a prehearing conference was held before Administrative Law Judges Sarah K. Wallace and Lisa D. Hardie and a procedural schedule was established.

During the course of the proceeding, the following parties were granted leave to intervene as parties: the Industrial Customers of Northwest Utilities (ICNU); Fred Meyer Food Stores and Quality Food Centers, Divisions of the Kroger Co. (Kroger); the Klamath Water Users Association (KWUA); and Portland General Electric Company (PGE). The Citizens' Utility Board (CUB) intervened as a matter of right under ORS 774.180.

Public comment hearings were held in Bend, Oregon, on May 27, 2009; in Portland, Oregon, on June 9, 2009; and in Medford, Oregon, on June 18, 2009. Extensive testimony was filed addressing the Company's application prior to the filing of the stipulations, including three rounds of testimony by Pacific Power from thirteen Company witnesses;[4] as well as a round of testimony by intervenors and the Staff of the Public Utility Commission of Oregon (Staff). Staff presented testimony from thirteen witnesses; ICNU presented testimony from two witnesses; ICNU and CUB presented joint testimony from two witnesses; and Kroger and KWUA each presented testimony from one witness.

Settlement conferences took place on June 24, 2009, August 20, 2009, and September 10, 2009.

On September 25, 2009, two stipulations were filed addressing the issues in this docket: a unanimous stipulation addressing rate spread and rate design issues, and a non-unanimous stipulation addressing revenue requirement issues. The sole party objecting to the revenue requirement stipulation was ICNU. Together, these stipulations addressed all issues raised by Pacific Power's filing.

On October 21, 2009, ICNU filed objections to the revenue requirement stipulation, along with supporting testimony. The parties to the revenue requirement stipulation filed reply testimony on October 29, 2009. The parties waived cross-examination and oral argument and filed briefs addressing contested issues on November 25, 2009, and December 10, 2009.

III. DISCUSSION

We divide our discussion into two parts. We first address the revenue requirement stipulation (Stipulation), beginning with an overview of the Joint Parties'

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[3] *See* Order No. 09-150.

[4] Pacific Power filed opening testimony with its application on April 2, 2009, supplemental testimony pursuant to Commission ruling on June 5, 2009, and reply testimony on August 31, 2009. On June 15, 2009, Pacific Power filed supplemental testimony relating to its Transition Adjustment Mechanism (TAM), but the TAM issues were ultimately resolved as part of a stipulation in another docket. *See* Pacific Power's Notice of Resolution of Issues in Docket UE 210 in Docket UE 207 Stipulation (Sept 30, 2009).

agreement, a discussion of ICNU's objections, and our resolution of the issues. We then discuss the unanimous stipulation on rate spread and rate design.

A. Overview of Revenue Requirement Stipulation

This Stipulation addresses all issues in the docket with the exception of rate spread and rate design issues, which are the subject of a separate agreement. The signatories to the Stipulation (hereafter, the Joint Parties) include all active parties except ICNU.[5] If approved, the Stipulation would reduce Pacific Power's proposed increase in test period revenue requirement from $92.1 million, or 9.1 percent, to approximately $41.5 million, or 4.4 percent.[6] The Stipulation also moves the recovery of certain regulatory assets to separate tariff riders. When these tariff riders are included, the Stipulation proposes a 4.6 percent overall rate increase.

1. Rate of Return and Taxes in Rates

The Stipulation sets Pacific Power's rate of return at 8.08 percent and addresses all issues associated with the cost of capital. Although the Joint Parties do not agree on specific capital components, the Joint Parties derive the 8.08 percent rate of return consistent with the table below:

Capital Component	% Capitalization	Cost	Weighted Cost
Long-term Debt	48.70%	5.960%	2.90%
Preferred Stock	0.30%	5.410%	0.02%
Common Equity	51.00%	10.125%	5.16%
TOTAL	100.00%		8.08%

The Joint Parties agree that the table above should be used for the calculation of taxes collected in rates for Oregon and for other regulatory purposes. The Joint Parties also agree that the tax expense levels generated by the Company's revenue requirement model should be calculated in accordance with Exhibit B to the Stipulation.

The stipulated 8.08 percent rate of return represents a reduction in the Company's original request of 8.55 percent, and would reduce the Company's original $92.1 million rate increase request by approximately $22.5 million. It also represents an overall reduction in the Company's *currently authorized* rate of return of 8.16 percent.

2. Prudence of Major Resource Additions

The Joint Parties agree that Pacific Power's acquisition of the following generating resources was prudent: the Lake Side natural gas plant, the Chehalis natural gas plant, and three wind resources, including Seven Mile Hill II, Glenrock III, and High Plains. The Joint Parties agree that these resources are used and useful, and that their costs should be included in the Company's Oregon rate base.

[5] Although PGE intervened in this docket, it did not actively participate in the proceedings.
[6] Exhibit A to the Stipulation summarizes the stipulated adjustments to Pacific Power's Oregon-allocated results of operations.

3. New Tariff Riders

Under the Stipulation, the Company will recover the remaining amortization for certain regulatory assets through three new tariff riders. The riders will be designed to collect the following balances:

> Pacific Power's Oregon Transition Plan: $2.008 million amortized through January 31, 2011.
>
> MidAmerican Energy Holdings Company Change-in-Control Severance: $4.709 million, amortized at $2.144 million per year through March 31, 2012.
>
> Grid West: $1.073 million, amortized at $0.401 million per year through December 31, 2012.

These regulatory assets will be recovered through new Schedules 193, 194, and 195.

4. Other Adjustments

The Joint Parties explain that the Stipulation includes a $16.3 million decrease in Administrative and General (A&G) expenses related to 401(k) expense, insurance expense, workers compensation expense, challenge grants, and FAS 112 expense. The A&G adjustments also reflect resolution of Staff's proposed adjustments associated with uncollectibles, incentives, and insurance; Staff and ICNU-CUB's adjustments associated with incentives, benefits, and pensions; and ICNU-CUB's adjustments associated with wages.[7]

The stipulated revenue requirement includes a $1.2 million decrease in connection with Distribution Operations and Maintenance (O&M) adjustments recommended by Staff related to Construction Work in Progress (CWIP), meals and entertainment, and escalation factors, a $1.6 million decrease related to Transmission O&M and property tax adjustments, and an $8.9 million decrease for various rate base adjustments. The Joint Parties explain that the adjustments to rate base include the removal of the revenue impact of the new tariff riders discussed above, a change in allocation factors, embedded cost differential updates, and other rate base adjustments related to Staff's opening recommendations.

In total, the stipulated adjustments reduce Pacific Power's original filed revenue requirement by $50.6 million and produces a stipulated revenue requirement increase of $41.5 million.

5. Testimony in Support of the Stipulation

Pacific Power, Staff, CUB, Kroger, and KWUA testify that they have reviewed the stipulated revenue requirement adjustments and agree that the Stipulation

[7] ICNU and CUB initially presented joint testimony on these issues.

results in fair, just, and reasonable rates. The Joint Parties urge the Commission to adopt the Stipulation.

Staff explains that after filing its opening testimony, it analyzed the testimony of other parties, as well as Pacific Power's rebuttal testimony. Staff believes that reasonable minds can disagree on methodologies and escalations in forecasting specific items, but based on its review, Staff concludes that the stipulated revenue requirement represents a compromise of different positions, represents a reasonable resolution of revenue requirement issues, and results in fair, just, and reasonable rates.[8]

CUB explains that although it would prefer that rates not increase, "that outcome is not supportable in this case."[9] CUB believes Pacific Power's filing reflects "significant capital investment in new generating resources that will provide benefits to customers," and believes that the Stipulation, along with the rate spread settlement and resolution of issues in docket UE 207, "produces rates for 2010 that are fair and are representative of the Company's cost of providing service to customers."[10]

B. Objections to Revenue Requirement Stipulation

ICNU challenges a number of elements of the Stipulation, including the assumed return on equity and common equity ratios included in the stipulated rate of return, the amount of Oregon-allocated wages and salaries, and the amount of rate base included in the Stipulation. ICNU also urges the Commission to adopt specific conditions for the treatment of renewable energy certificates. Before we address these issues, however, we note that the parties also disagree about the legal standard applicable to our review of the Stipulation. We address this issue first.

1. Legal Standard

a. Parties' Positions

ICNU argues that the Stipulation is a "black box" settlement that fails to adequately identify specific costs or methodologies used to calculate the proposed rate increase. ICNU complains that the Stipulation is not sufficiently detailed to allow ICNU to determine whether the parties to the Stipulation accepted or rejected specific adjustments proposed by Staff or intervenors in their opening testimony, putting ICNU in the "untenable position of only having an overall revenue requirement number, but no real idea how the number was obtained."[11] Because of this, ICNU argues, the rate increases proposed in the Stipulation are not fully supported by the evidence.

The Joint Parties argue that ICNU misstates the legal standard for evaluating stipulations. When considering a stipulation, the Commission does not

[8] Joint-Revenue Requirement/100, Garcia, *et al.*/9. The Joint Parties' opening and reply testimony will be subsequently referred to as "Joint/__" and "Joint Reply/__."
[9] Joint/100, Garcia, *et al.*/11.
[10] *Id*.
[11] ICNU Opening Brief at 14 (citing ICNU/700, Early/7).

evaluate and approve every adjustment, but instead evaluates the validity of the proposed rates based on the reasonableness of the overall rates, not the theories or methodologies used or individual decisions made. In any case, the Joint Parties argue, the Stipulation is not truly a "black box" settlement because it explains the agreed level of overall revenue requirement and agreed adjustments to the Company's proposed revenue requirement, and provides a results-of-operations / summary view of each stipulated adjustment.

The Joint Parties assert that adopting ICNU's standard for settlement—that is, requiring stipulating parties to reach agreement with respect to specific adjustments and methodologies, rather than end results—would preclude settlement in many cases, thereby undermining Commission policy of encouraging parties to voluntarily resolve issues to the extent that settlement is in the public interest.

CUB, who filed opening testimony jointly with ICNU, states that while ICNU may disagree with the level of detail in the Stipulation, CUB is concerned that "when rate cases get so focused on very specific cost elements, utilities may be encouraged to file deferrals when the actual costs are greater than the forecasts."[12] CUB states that its months of forecast review have convinced it that the "level of cost detail in the Stipulation is more than adequate, and, more importantly, that the proposed rates are reasonable."[13]

b. Resolution

The Commission has the broad powers to set just and reasonable rates.[14] As with any rate increase, Pacific Power bears the burden to show that the proposed rate change is just and reasonable.[15] 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 have recognized, however, that issues in a general rate case typically reflect judgments along a continuum of outcomes and can rarely be reduced to one "right" number in any cost category.[16] When considering a stipulation, therefore, we may evaluate the validity of the rates based on "the reasonableness of the overall rates, not the theories or methodologies used or individual decisions made."[17] 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.[18]

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[12] Joint/200, Garcia, *et al.*/23.
[13] *Id.* (emphasis in original).
[14] *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).
[15] *See* ORS 757.210. *See also, In re PacifiCorp*, Docket UM 995, Order No. 02-469 at 4 (July 18, 2002).
[16] *See, e.g., In re Avista Corp.*, Docket UG 186, Order No. 09-422 at 8 (Oct 26, 2009).
[17] *In re Portland Gen. Elec. Co*., Docket DR 10, *et al*., Order No. 08-487 at 7-8 (Sept. 30, 2008).
[18] *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.").

2. Rate of Return

ICNU objects to the stipulated rate of return (ROR), challenging the return on equity (ROE) and the common equity ratio found in the Stipulation's table of capital components. ICNU argues that the Company's ROE should be no higher than 10 percent, and its common equity ratio no higher than 50.2 percent. ICNU's adjustments to these components of the stipulated ROR would lower the overall ROR from 8.08 percent to 7.99 percent, and would reduce the stipulated rate increase by approximately $5.5 million.

a. Parties' Positions

The Joint Parties agree to support an overall allowed ROR of 8.08 percent, but do not agree among themselves on the individual capital components that make up that return. Nevertheless, the Stipulation includes a table detailing the various ROR components that, as explained by the Joint Parties, are "notional" only, to be used only for Oregon regulatory purposes. The table includes a notional ROE of 10.125 percent and a common equity ratio of 51 percent.

ICNU challenges the reasonableness of the notional ROE and common equity ratio. First, ICNU contends the notional 10.125 percent ROE is "higher than the midpoint of a reasonable return on equity estimated range for [Pacific Power] in this proceeding."[19] Second, ICNU asserts that the common equity ratio in the Stipulation is too high and should be lowered from 51.0 percent to 50.2 percent. According to ICNU, Pacific Power originally requested a 51.2 percent common equity ratio based on a planned $200 million equity contribution, but failed to reduce that ratio when it reduced the equity contribution to $125 million. In addition, ICNU argues Pacific Power overstates its common equity ratio by assuming an estimated retained earnings of 10 percent, yet asserts elsewhere in its filing that it will earn only 6.157 percent in 2009. Finally, ICNU states that Pacific Power recently proposed a 50.3 percent common equity ratio in a rate case in the State of Washington, further indicating that the Company's request for a 51 percent common equity ratio is too high.[20]

The Joint Parties respond that the notional ROE is supported by the record, and that ICNU's objections to the notional common equity ratio are based on improper calculations and inapplicable comparisons. They urge the Commission to focus on the reasonableness of the overall ROR, and ask the Commission to deny ICNU's objections.

b. Resolution

As we have explained, our key concern is whether the stipulated rates are, as a whole, just and reasonable. When reviewing a stipulation, we are not required to

[19] ICNU/500, Gorman/3.

[20] We note that the difference in the parties' positions on this point is extremely narrow. ICNU's proposed adjustment to the common equity ratio would lower the overall ROR only three one-hundredths of a percent (from 8.08 percent to 8.05 percent).

approve each individual cost component of those rates. The stipulated ROR of 8.08 percent represents a significant reduction in Pacific Power's opening request of 8.55 percent and an overall *decrease* in the Company's currently authorized ROR of 8.16 percent. We find the stipulated ROR to be supported by competent evidence, and conclude that it represents a reasonable resolution of this issue.

Given this conclusion, we need not address ICNU's specific arguments relating to the notional ROE and common equity ratio contained in the Stipulation. Nevertheless, even examining these issues on their merits, we find these notional figures to be supported by the evidence. First, we note that the notional ROE falls within the range of reasonable ROE results proposed by ICNU's own witness. Before the Stipulation was filed, ICNU's ROE witness Gorman recommended a ROE of 10.0 percent based upon various ROE analyses that yielded a "recommended ROE range" of 9.6 percent to 10.4 percent.[21] Although the notional 10.125 ROE is slightly higher than the mid-point of that range, it falls squarely within ICNU's reported range of reasonable ROEs.

Second, we similarly find the notional capital equity ratio to be supported by the evidence. At the outset, we note that, contrary to ICNU's argument, the reduction in Pacific Power's planned equity contribution is reflected in the stipulated common equity ratio. As Pacific Power explained, the notional capital equity ratio was lowered from 51.2 percent to the current 51 percent in response to the lower contribution.[22] We also agree with the Joint Parties that ICNU's methodology for calculating the common equity ratio relies on an inappropriate mismatch of time periods. As explained by Pacific Power witness Bruce Williams. ICNU should have used the projected ROE for Oregon during 2010 and applied that ROE to the beginning 2009 common equity level to ensure an appropriate and consistent matching of returns, capital structure balances, and periods of time. ICNU also inappropriately applied Pacific Power's Oregon jurisdictional return to the Company's total operations, when the Company actually finances operations in all six of its state jurisdictions with an aggregate capital structure.[23]

In summary, we find the stipulated ROR of 8.08 percent to be reasonable and deny ICNU's objections to the notional ROE and common equity ratio figures contained in the Stipulation.

3. Wages and Salaries

ICNU raises two issues related to Pacific Power's proposed expenses for wages and salaries. First, ICNU argues that all non-union wage and salary increases should be removed from proposed rates, along with all bonus and incentive compensation. Second, ICNU argues that the allocation of payroll costs in the Stipulation should be adjusted to correct for an over-allocation of labor costs to Pacific

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[21] *Id.* at 39.
[22] *See* PPL/307, Williams/3 (lowering Pacific Power's recommended common equity ratio from 51.2 percent to 51.0 percent, due to the reduction in the Company's planned equity contribution).
[23] *See* PPL/307, Williams/4-7.

Power's Oregon jurisdiction. Together, these proposed adjustments would reduce the stipulated rate increase by approximately $21 million.[24]

a. Non-Union Increases; Bonus and Incentive Compensation

(1) Parties' Positions

ICNU argues that the Stipulation includes non-union wage and salary increases that should be removed because they are unnecessary to retain employees in the current economic climate. According to ICNU, it is "unconscionable to increase utility rates so that utility employees can receive wage increases at the expense of utility customers."[25] The removal of wage and salary increases would reduce the stipulated rate increase by $1.8 million. ICNU also asserts that the poor economy warrants the removal of all bonus and incentive compensation from rates, which would reduce the stipulated rate increase by an additional $10.2 million.[26]

The Joint Parties assert that the wage and salary increases included in the stipulated rates are prudently incurred, required to maintain a competent workforce, and are fully supported by the record. The Joint Parties also note that Pacific Power did not include any increase to non-union wages for the 2010 test year, making the stipulated labor costs all the more reasonable.[27]

According to the Joint Parties, the only basis given for ICNU's adjustment is the state of the economy, an assertion that is misplaced because the Stipulation already takes the state of the economy into account. In testimony supporting the Stipulation, the Joint Parties state:

> The Parties recognize that the current economic climate has placed significant financial pressure on the Company's customers. The terms of the Stipulation reflect this reality. Although the Company had not filed a general rate case in three years prior to filing this rate case, it accepted many of the adjustments proposed by Staff, CUB, and ICNU, and lowered its requested rate increase from 9.1 percent to 4.6 percent—nearly one-half of its original request. The compromises reflected in the agreement were made with a full understanding of the current economy.[28]

[24] Removing non-union wage and salary increases would reduce the stipulated rate increase by $1.8 million; removing all bonus and incentive compensation would reduce the rate increase by $10.2 million; modifying the allocation of payroll costs in accordance with ICNU's recommendations would reduce the rate increase by another $9.0 million. ICNU Opening Brief at 25 (Nov 25, 2009).
[25] ICNU/600, Blumenthal/8-9. ICNU does not recommend excluding wage increases for union employees because the Company is contractually obligated to increase these wages. *Id.* at 8.
[26] ICNU/600, Blumenthal/8-9.
[27] Joint Parties Opening Brief at 9-10 (Nov. 25, 2009) (citing Joint Reply/200, Garcia, *et al.*/12).
[28] Joint/200, Garcia, *et al.*/4.

In any case, the Joint Parties assert, ICNU's only evidentiary support for freezing non-union wages is inconsistent. On one hand, ICNU asserts that the ailing economy justifies a freeze on non-union employee wages; on the other hand, ICNU asserts that the improving state of the economy renders the Stipulation's notional return on equity too high.[29]

The Joint Parties also assert that ICNU's proposed adjustment, even if warranted, is calculated incorrectly. ICNU's witness Ellen Blumenthal asserts that she removed a 3.8 percent increase that occurred in January 2009,[30] but her adjustment actually removes non-union wage and salary increases for a total of 3.5 years, from the July 2007 beginning of the base period through the December 2010 end of the test period.[31]

With respect to ICNU's assertions that all bonus and incentive compensation should also be removed from the stipulated rates, the Joint Parties point out that in opening testimony, Staff proposed removing 100 percent of officer bonuses and 50 percent of the annual incentive plan bonuses, a traditional sharing percentage, and ICNU proposed a nearly identical adjustment. The Joint Parties assert that the Stipulation already reflects Staff's adjustment. Finally, the Joint Parties complain that ICNU's current position on bonus and incentive compensation was raised only after the Stipulation was filed and should have been raised earlier. The Joint Parties agree the Stipulation reflects a traditional and appropriate adjustment to bonus and incentive compensation, and that no further adjustments should be made.

(2) Resolution

We note at the outset that it is not possible to determine from the Stipulation precisely which stipulated adjustments to wages, salaries, and bonuses are included under the Stipulation's broad heading of "A&G adjustments." The Stipulation includes a total of $16.3 million in adjustments to Pacific Power's initial request for A&G expenses, a category that includes not only the adjustments contested by ICNU, but adjustments to other expenses as well, such as 401(k) expense, insurance expense, and uncollectible expenses.[32] Our responsibility is not to examine any of these specific cost categories in detail, but rather to determine whether the Stipulation as a whole results in just and reasonable rates.

Even reviewing this issue narrowly, however, we find that the Joint Parties have adequately supported their position with respect to wages, salaries, bonus, and incentive plans. The Company's non-union wage and salary expenses are reasonable and include no additional increases for 2010. We find that the Joint Parties have also

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[29] Joint Parties' Opening Brief at 9 (citing ICNU/500, Gorman/4).
[30] *See* ICNU/600, Blumenthal/8.
[31] Joint Reply/200, Garcia, et al./12. Staff also testified that it does not support ICNU's proposed adjustment because of "incorrect assumptions in her calculations of historic and appropriate test year wage & salary levels." Joint/100, Garcia, *et al*./10.
[32] *See* Joint /100, Garcia, *et al.*/6. Staff's opening testimony recommended reducing Pacific Power's requested A&G by $16.8 million. *See* Joint /100, Garcia, *et al.*/10

adequately supported their position with respect to bonus and incentive payments. Pacific Power explained the purpose behind its bonus and incentive programs in detail,[33] and the evidence shows that the stipulated adjustments to these programs generally reflect Staff's proposal (and ICNU's original similar proposal) that 100 percent of officer bonuses and 50 percent of annual incentive plan bonuses be removed from rates. This sharing arrangement has traditionally been supported by the Commission, and we see no reason to deviate from that tradition here.[34]

While ICNU's concerns about the economy are well taken, they do not, by themselves, demonstrate the impropriety of the Joint Parties' positions on wage, salary, bonus, and incentive expenses. All parties concede that the economy is struggling, but the evidence shows that the stipulated rate increase represents a significant reduction from the increase originally sought by Pacific Power. The Joint Parties assert that this reduction was implemented specifically with the state of the economy in mind.[35] Given this assertion, we find the stipulated compromises on A&G adjustments to be reasonable and deny ICNU's objections.

b. Allocation of Labor Costs

(1) Parties' Positions

ICNU argues that the Stipulation allocates too high a share of the Company's payroll costs to the Company's Oregon jurisdiction. According to ICNU, the Company's data demonstrate that the 29.5 percent allocation in Pacific Power's filing is inaccurate, and that Pacific Power should allocate only 27.8 percent of its total payroll to Oregon.[36] Moreover, ICNU asserts, Oregon's overall share of Pacific Power's costs has been declining and the 29.5 percent allocation is greater than the actual allocations to Oregon in each of the last five years.[37]

According to ICNU, Pacific Power's method for calculating the allocation also relies inappropriately on "budgets and estimates," rather than actual allocations from Federal Energy Regulatory Commission (FERC) clearing accounts. ICNU's adjustment, by contrast, relies on actual data from FERC accounts and the most recent data provided by the Company.[38] ICNU's adjustment would reduce the stipulated revenue requirement by approximately $9 million.

The Joint Parties dispute ICNU's assertion that the Company used "budgets and estimates" to calculate its labor allocation. They explain that the

[33] *See, e.g.,* PPL/800, Wilson/3-9.
[34] *See generally, In re Northwest Natural Gas Co.*, Docket UG 132, Order No. 99-697 at 45-46.
[35] We agree with the Joint Parties that ICNU has not adequately explained its change in position with respect to some of these adjustments. Witness Blumenthal specifically reviewed Pacific Power's testimony on wage and salary increases, as well bonuses and incentive plans, in July 2009. *See* ICNU-CUB/400, Blumenthal/2-3 (describing ICNU's opening position). ICNU changed its position on these issues in October 2009 without identifying new information sufficient to justify such changes.
[36] ICNU/600, Blumenthal/5-7, 9.
[37] ICNU/600, Blumenthal/9.
[38] ICNU/600, Blumenthal/5-7, 9.

Company's accounting system runs labor allocation settlements on a total cost basis. ICNU, however, sought to break out wages and salaries from other labor costs and allocate them separately. The Joint Parties attempted to provide ICNU with wages and salaries estimates to allow ICNU to perform this analysis, but the Joint Parties assert that other elements of Pacific Power's labor costs are allocated on the same basis as wages and salaries, providing no reasonable basis for separately calculating wages and salaries.[39] The Joint Parties maintain that Pacific Power's Oregon-allocated labor costs, taken as a whole, are accurate and supported by correct data.[40] Finally, the Joint Parties assert that ICNU inappropriately uses a historical trend to calculate its proposed allocation, when load forecasts should be used for consistency with the development of other test period revenues.[41]

(2) Resolution

We find that the evidence supports a 29.5 percent allocation for Pacific Power's Oregon labor expenses. The Joint Parties agree that Pacific Power's accounting system runs data for labor costs on an aggregated basis, that wages and salaries are allocated on the same basis as Pacific Power's other labor costs, and that the Company's actual aggregated labor costs support a 29.5 percent allocation. ICNU has not explained to our satisfaction why its witness segregated Pacific Power's wages and salaries from the rest of Pacific Power's labor costs in developing its own allocation of labor costs. We also agree with the Joint Parties that test year labor costs should be calculated using load forecasts, for consistency with the development of other test period revenues. We deny ICNU's objection on this point.

4. Used and Useful

a. Parties' Positions

In its opening testimony, Staff recommended approximately $19 million in reductions to Pacific Power's requested revenue requirement related to rate base. Staff's proposed reductions related to a number of items, including transmission rate base, wind plant rate base, costs related to the Threemile Knoll Substation, adjustments to miscellaneous rate base items, and associated adjustments to depreciation and amortization.[42] Staff asserted that these adjustments related primarily to costs that it considered too high, rate base items scheduled to go into service subsequent to rates going into effect, or proposed increases that Staff believed were not "known and measurable" based on the information Staff had obtained.[43] In the Stipulation, Staff

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[39] Joint Reply/200, Garcia, *et al.*/17.
[40] *See, e.g., id.* at 15. The Joint Parties assert that Pacific Power's actual Oregon allocation was 30.59 percent for 2006, 30.10 percent for 2007, and 30.37 percent for 2008. *Id.* at 16.
[41] Joint Reply/200, Garcia, *et al.*/17-18.
[42] *See* Staff/102, Garcia/1-2.
[43] *See* Staff/100, Garcia/6-12.

reduced its proposed rate base adjustments from $19 million to approximately $9 million on a revenue requirement basis.[44]

In its objections to the Stipulation, ICNU contends that the Stipulation fails to remove from the stipulated rate increase a certain but unspecified amount of rate base items that fail to comply with ORS 757.355.[45] ICNU contends that because Staff's initial adjustment for items that it believed were not "used and useful" was $13.725 million, and the rate-base related adjustment to the stipulated revenue requirement is only $8.9 million, some of the "illegal rate base" originally identified by Staff is necessarily reflected in the stipulated rate base.

ICNU asserts that the black box nature of the Stipulation makes it difficult to determine how much of the stipulated rate increase represents improperly included rate base items, but estimates that $4.8 to $10.3 million of the stipulated rate base should be eliminated.[46] Because the details of the stipulated adjustment to rate base were not provided, ICNU recommends that the Commission remove $10.3 million from the stipulated revenue requirement to ensure that the rate base approved by the Commission complies with Oregon law.[47]

The Joint Parties respond that the stipulated rates appropriately reflect only plant that complies with ORS 757.355. According to the Joint Parties, Staff witness Deborah Garcia originally proposed removing several types of rate base items from rates, including rate base items scheduled to go into service after rates took effect, as well as rate base items with "monthly" or "variable" in-service dates.[48] Staff initially argued that these rate base additions were not "known and measurable" and should therefore be excluded from rates pursuant to ORS 757.355.[49] In reply testimony, Pacific Power argued that Staff's interpretation of "known and measurable" was contrary to Commission precedent and would effectively preclude the use of a forecast test year.[50] Pacific Power also testified that Staff's proposal would reduce the Company's rate base to below the Company's actual June 2009 level of base rates.[51]

In resolving the issue for settlement, the Joint Parties explain, they agreed to reduce the level of the Company's rate base to address Staff's position on ORS 757.355, and removed from proposed rates the amount of miscellaneous rate base

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[44] *See* Exhibit A to the Stipulation.
[45] ICNU Opening Brief at 30 (citing ICNU/700, Early/6).
[46] ICNU states that it submitted data requests to the stipulating parties in an effort to determine "how much of the not presently used and useful costs would be included in rates under the Settlement," but states that it was not given substantive answers. ICNU Opening Brief at 30.
[47] ICNU Opening Brief at 30. ICNU recommends that the $10.3 million adjustment should be updated based on the capital structure the Commission ultimately adopts for Pacific Power. *Id.*
[48] Joint Parties Opening Brief at 8. Staff also recommended removing some discrete items, such as a treadmill and amounts for CWIP from rate base. These items totaled approximately $400,000. *See* Staff/100, Garcia/9.
[49] *See* Staff/100, Garcia/7-8.
[50] *See* PPL/706, Dalley/18, 21-22.
[51] *Id.* at 23.

that Staff ultimately believed might not be used and useful in the test year.[52] After reviewing testimony and data request responses, and conducting discussions with Pacific Power, the Joint Parties agree the Stipulation includes only Oregon-allocated net electric plant in service that complies with ORS 757.355. Specifically, the Joint Parties assert that the Stipulation now includes a level of Oregon-allocated net electric plant in service that is almost $50 million lower than the Company's net plant in service will be at the beginning of 2010. Thus, the Joint Parties assert, regardless of how ORS 757.355 is interpreted, the stipulated level of rate base reflects only property that will be used and useful in the rate effective period.

b. Resolution

ORS 757.355 prohibits a public utility from collecting in customer rates the costs of any property not presently used for providing utility service to those customers. Staff initially proposed a number of rate base reductions removing property that Staff was uncertain would be "used and useful" in the appropriate time period, but adjusted its proposal after reviewing Pacific Power's reply testimony and conducting further discussions with the Company.

The primary cost driver for Pacific Power's rate request is new investment. This investment includes, among other things, the addition of two natural gas plants, three wind resources to serve customers, investment in transmission and distribution plant, and investment in hydroelectric plant to conform with various hydro relicensing agreements.[53] As CUB testified in support of the Stipulation,

> CUB cannot ask Oregon utilities to stop making investments in their respective service territories without future impacts to service and system performance. CUB understands that making cost-effective investments today will lead to lower rates in the future.[54]

ICNU is correct that the Stipulation is not sufficiently detailed to allow us to ascertain which specific adjustments were ultimately made to Pacific Power's requested rate base, or to determine the justifications for those adjustments. But the undisputed evidence shows that the amount of Oregon-allocated plant contained in the Stipulation is lower than what Pacific Power's Oregon-allocated net plant in service will be at the time these rates will go into effect. Specifically, the Stipulation provides for Oregon-allocated net electric plant in service of approximately $3.33 billion, while Pacific Power's forecast ending balance for Oregon-allocated net electric plant in service

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[52] *See* Joint Reply/200, Garcia, *et al.*/8. The Joint Parties argue that Staff adjusted its proposed reduction to rate base in response to Pacific Power's reply testimony to $35.2 million on an Oregon-allocated basis. The Stipulation reflects an adjustment to electric plant in service related to the miscellaneous rate base of $35.4 million on an Oregon-allocated basis. *See* Joint Reply/201; Stipulation, Exhibit A. In other words, the Joint Parties assert, the Stipulation includes a larger adjustment to rate base than Staff believed should be removed under Staff's (and ICNU's) interpretation of ORS 757.355.

[53] PPL/100, Reiten/2-4.

[54] Joint Reply/200, Garcia, *et al.*/23-24.

is approximately $3.38 billion.[55] Given this evidence, and despite the parties' contentions about specific rate base adjustments, it is clear that the Stipulation will allow Pacific Power to collect in rates only the costs of property presently providing service to customers in conformance with ORS 757.355. We therefore deny ICNU's objection on this point.

5. Renewable Energy Credits

a. Parties' Positions

Although the Stipulation does not specifically address the issue of Renewable Energy Certificates (RECs), ICNU recommends that the Commission require Pacific Power to place the gain on any sales of Oregon-allocated RECs into a balancing account for refund to customers with interest. ICNU asserts that Pacific Power is currently selling RECs, yet neither the Stipulation nor Commission rules prevent Pacific Power from selling Oregon-allocated RECs and retaining the benefits for shareholders. ICNU contends that Oregon administrative rules, which include reporting requirements, do not prevent Pacific Power from selling Oregon-allocated RECs and transferring the benefits to shareholders. ICNU is concerned that the Commission may lack authority to recover such benefits for ratepayers once any such sales have occurred.[56]

The Joint Parties contend that ICNU's proposed condition is unnecessary in light of the Commission's recently adopted rules on RECs, as well as the fact that the Company is banking all Oregon-eligible RECs in 2010. The Joint Parties argue that ICNU's proposal would provide no additional benefits beyond what is already required by Oregon rules.

b. Resolution

The Commission's rules governing treatment of REC sales include reporting requirements, but they do not explicitly require a utility to seek preapproval of REC sales.[57] Commission Order No. 07-083 makes clear, however, that the sale of RECs will be treated as a property sale with gains on sale being placed in a property sales balancing account for return to customers. Generally speaking, then, any REC sale over $100,000 is subject to Oregon law and Commission rules requiring Commission approval prior to the sale of utility property.[58]

ICNU's proposed condition on REC sales was taken from Staff's opening testimony. Staff originally testified as follows:

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[55] Joint Reply/200, Garcia, *et al.*/9. No party contends that any portion of this rate base was acquired imprudently.
[56] ICNU Opening Brief at 31-32.
[57] *See* OAR §§ 860-083-0350, -400.
[58] *See, e.g.*, ORS 757.480 (requiring a utility to obtain Commission approval before it sells, leases, assigns, or otherwise disposes of property valued in excess of $100,000); OAR 860-027-0025.

> [B]ecause [Pacific Power] estimates that it will have sufficient RECs allocated to Oregon to meet RPS requirements for years 2011 through 2016, if the Company is able to and chooses to sell Oregon-allocated RECs, the Company should place the gain on the sale to the property sales balancing account for refund to customers with interest accrual from the date of sale using the Commission approved rate of return until amortization begins. This proposed treatment is consistent with Commission Order No. 07-083 (UP 236), which established the sale of RECs as a property sale with gains on sale being placed in a property sales balancing account for return to customers. Additionally, [Pacific Power] should report in its semi-annual Property Sales Balancing Account report any REC sales that occurred during the reporting period.[59]

Staff subsequently dropped these proposed conditions and endorsed the Stipulation without any conditions on REC sales. Staff's change of position appears to be based on Pacific Power's assertion that the Company will be banking, rather than selling, all of its Oregon-eligible RECs in 2010. We will accept the Company's assertion that it does not intend to sell RECs in 2010. In the event the Company changes its position and seeks to sell Oregon-allocated RECs, however, we direct the Company to file a property sales application for Commission review and approval.

6. Conclusion

We find the Joint Parties have demonstrated that the revenue requirement Stipulation is supported by substantial and competent evidence. Pacific Power has explained that the primary cost driver for its rate request is new investment. While we would prefer not to impose a rate increase on customers during difficult economic times, Pacific Power is entitled to recover in rates the costs of property currently being used to serve customers. Although the Stipulation allows Pacific Power to recover the cost of its new investment in rates, it also reduces Pacific Power's allowed ROR from 8.16 percent to 8.08 percent. While the evidence on specific issues was contested, the Stipulation and the record as a whole support the conclusion that the Stipulation is just and reasonable. Consequently, we find the Stipulation should be adopted.[60]

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[59] Staff/300, Dougherty/9.

[60] We note that paragraph 8 of the Stipulation states that "[f]or the calculation of taxes collected in rates for Oregon and other Oregon regulatory purposes, the Parties agree that such analysis will use the rate of return components specified in Table 1 below." With respect to Senate Bill 408 tax filings, we interpret this statement to mean that the components in Table 1 underlie the revenue requirement authorized in this general rate proceeding, including the final net revenues, gross revenues, and income taxes that will be used in the tax filings to calculate the ratios for "taxes authorized to be collected in rates" under OAR 860-022-0041(2)(s)(ii) and (iii). We also interpret this statement as not superseding or modifying any of the calculations directed by any other sections of OAR 860-022-0041. With that understanding, we approve paragraph 8 of the stipulation.

C. Stipulation on Rate Spread and Rate Design

The Rate Spread and Rate Design Stipulation (Rate Spread Stipulation) filed by the parties on September 25, 2009, resolves all rate spread and rate design issues in this docket. The parties to the Rate Spread Stipulation (Stipulating Parties) include all active participants in this docket.

The Stipulating Parties agree to a rate spread to implement Pacific Power's new revenue requirement that allocates the stipulated rate increase in the following manner:

Rate Schedule	Net Rate Increase Factor
Residential (Schedule 4)	76.8%
General Service < 31 kW (Schedule 23)	147%
General Service 31-200 kW (Schedule 28)	124%
General Service 201-999 kW (Schedule 30)	123%
Partial Requirements Service ≥ 1,000 kW (Schedule 47)	117%
Large General Service ≥ 1,000 kW (Schedule 48)	117%
Agricultural Pumping Service (Schedule 41)	117%
Public Street Lighting	117%

The Stipulating Parties agree to apply the net rate increase factors in this table to the overall general rate case net rate percentage increase for each rate schedule class. The net rates include the effect of all tariff riders. The Stipulating Parties agree that these factors represent a compromise among their differing positions that is acceptable to all parties.

The Rate Spread Stipulation also increases the residential basic charge from $7.50 per month to $8.00 per month, and modifies the rate design for Schedule 200 Supply Service. Except for these two modifications, the Stipulating Parties agree to the rate design proposed by Pacific Power in its filing.[61]

IV. CONCLUSION

We have reviewed the Revenue Requirement Stipulation and find the proposed provisions contained therein to be reasonable. Accordingly, this Stipulation, set forth in Appendix A to this order, should be adopted. We have reviewed the Rate Spread and Rate Design Stipulation and find the proposed provisions contained therein to be reasonable. Accordingly, this Stipulation, set forth in Appendix B to this order, should be adopted.

[61] The Rate Spread Stipulation also provides that if Pacific Power files a stand-alone TAM prior to filing its next general rate case, and the TAM might produce a rate decrease, the parties may address the level of Pacific Power's Rate Mitigation Adjustment in that TAM proceeding.

V. ORDER

IT IS ORDERED that:

1. The Revenue Requirement Stipulation by and between PacifiCorp, dba Pacific Power; the Staff of the Public Utility Commission of Oregon; the Citizens' Utility Board of Oregon; Fred Meyer Food Stores and Quality Food Centers, Divisions of the Kroger Co.; and the Klamath Water Users Association is adopted.

2. The Rate Spread and Rate Design Stipulation by and between PacifiCorp, dba Pacific Power; the Staff of the Public Utility Commission of Oregon; the Citizens' Utility Board of Oregon; the Industrial Customers of Northwest Utilities; Fred Meyer Food Stores and Quality Food Centers, Divisions of the Kroger Co.; and the Klamath Water Users Association is adopted.

3. The tariffs previously filed in this docket are permanently suspended.

4. PacifiCorp, dba Pacific Power, must file compliance tariffs consistent with this Order to be effective no earlier than February 2, 2010.

Made, entered, and effective JAN 26 2010.

Lee Beyer FKA
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 210

In the Matter of: PacifiCorp d/b/a Pacific Power's Request for a General Rate Increase in the Company's Oregon Annual Revenues	**REVENUE REQUIREMENT STIPULATION**

This Revenue Requirement Stipulation ("Stipulation") is entered into for the purpose of resolving the issues among the parties to this Stipulation related to PacifiCorp's (or the "Company") requested revenue requirement increase in this docket. This Stipulation does not address issues related to rate spread or rate design. The parties to this Stipulation and the Industrial Customers of Northwest Utilities ("ICNU") have filed a separate stipulation in this proceeding that resolves rate spread and rate design issues.

PARTIES

1. The initial parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board ("CUB"), Fred Meyer Stores and Quality Food Centers, divisions of The Kroger Company ("Kroger") and the Klamath Water Users Association ("KWUA") (together, the "Parties"). This Stipulation will be made available to the other parties to this docket, who may participate by signing and filing a copy of the Stipulation.

BACKGROUND

2. On April 2, 2009, PacifiCorp filed revised tariff sheets to be effective May 2, 2009, for Oregon that would result in a base price increase of approximately $92.1 million or 9.1 percent. PacifiCorp based its filing on a 2010 calendar year test period.

3. At the public meeting on April 21, 2009, the Public Utility Commission of Oregon ("Commission") suspended the Company's application for revised tariff sheets for a period of

nine months. Based on the suspension, the effective date of the revised tariff sheets would be February 2, 2010.

4. Pursuant to Administrative Law Judges Wallace's and Hardie's Prehearing Conference Memorandum of April 22, 2009, the parties to this docket convened a settlement conference on June 24, 2009. The parties held additional settlement conferences on August 20 and September 10, 2009. The settlement conferences were noticed and all parties were invited to participate.

5. As a result of the settlement conferences, the Parties have reached a settlement in this case resolving all issues related to revenue requirement. The net effect of this Stipulation reduces PacifiCorp's proposed increase in test period revenue requirement to $41.5 million, which will result in an overall increase of approximately 4.4 percent. The net overall increase, including the tariff riders discussed below, will be 4.6 percent. The effective date of these new rates is February 2, 2010.

AGREEMENT

6. The Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Parties agree that the adjustments and the rates resulting from their application are fair, just, and reasonable.

7. Revenue Requirement: The Parties agree to a total revenue requirement increase of $41.5 million in base rates, which in conjunction with the other terms identified below, represents a settlement of all revenue requirement issues in this case. Exhibit A includes an agreed-upon calculation of the $41.5 million increase in base rates based on resolution of adjustments proposed by the Parties. The Parties agree that the acceptance of these adjustments for purposes of settlement is not binding on Parties in future proceedings and does not imply agreement on the merits of adjustments.

8. Rate of Return and Taxes in Rates: The Parties agree that the Company's overall ROR should be set at 8.08 percent. The Parties do not agree on the individual capital

components that result in the ROR of 8.08 percent. Without accepting the individual capital components, the Parties derive the ROR of 8.08 percent consistent with Table 1 below. The Parties agree on the tax expense levels generated by the Company's revenue requirement model, which are calculated on a stand-alone basis and provided as Exhibit B. For the calculation of taxes collected in rates for Oregon and other Oregon regulatory purposes, the Parties agree that such analysis will use the rate of return components specified in Table 1 below:

Table 1

Capital Component	Percent Capitalization	Cost	Weighted Cost
Long Term Debt	48.70%	5.960%	2.90%
Preferred Stock	0.30%	5.410%	0.02%
Common Equity	51.00%	10.125%	5.16%
TOTAL	100.00%		8.08%

9. Prudence of Major Resource Additions: The Parties agree that the Company prudently acquired the following generating resources: Lake Side, Chehalis, Seven Mile Hill II, Glenrock III, and High Plains. The Parties agree the resources listed in this section are used and useful, and that the costs of the resources should be included in the Company's Oregon rate base.

10. AFUDC Equity Flow-Through: The Parties agree that the Company will use flow-through treatment for AFUDC equity in this and future cases, effective January 1, 2010. The Company agrees that this will not have an adverse affect on customers through SB 408 filings.

11. New Tariff Riders: The Company will recover the remaining amortization for the following regulatory assets through three new, separate tariff riders: Schedules 193, 194, and 195 as described and proposed in the Company's Reply Testimony of Mr. William R. Griffith

filed on August 31, 2009 in this docket. The tariff riders will be designed to collect the following balances over the specified amortization period:

- Transition Plan – Oregon: $2.008 million amortized through January 31, 2011.
- MEHC Change in Control: $4.709 million, amortized at $2.144 million per year through March 31, 2012.
- Grid West: $1.073 million, amortized at $0.401 million per year through December 31, 2012.

12. Rate Change Effective Date: The Parties agree that rates to recover the stipulated revenue requirement and new tariff riders will go into effect on February 2, 2010.

13. Tariff: Upon approval of this Stipulation and the Rate Spread and Rate Design Stipulation filed in this proceeding, PacifiCorp will file its revised tariff sheets and new tariff riders as a compliance filing in Docket UE 210, effective February 2, 2010.

14. Rate Spread and Rate Design: The Parties agree that this Stipulation does not resolve issues related to rate spread or rate design. The tariff sheets and new tariff riders filed pursuant to Section 13 of this Stipulation will reflect rates designed as agreed in the separate Rate Spread and Rate Design Stipulation, filed by the Parties and ICNU in this docket.

15. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. 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.

16. If this Stipulation is challenged by any other party to this proceeding, the Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

17. 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.

18. 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 this 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.

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

This Stipulation is entered into by each party on the date entered below such Party's signature.

STAFF

By: ______________________

Date: 9/25/9

CUB

By: ______________________

Date: ______________________

KROGER

By: ______________________

Date: ______________________

KWUA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: Rt Jenks

Date: 9-25-09

KROGER

By: ______________________

Date: ______________________

KWUA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

KROGER [signature]

By: Kurt J. Boehm

Date: 9-25-09

KWUA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

KROGER

By: ______________________

Date: ______________________

KWUA

By: Greg Adams [signature]

Date: 9/25/09

PACIFICORP

By: ______________________

Date: ______________________

STAFF	CUB
By: ____________________	By: ____________________
Date: ____________________	Date: ____________________
KROGER	KWUA
By: ____________________	By: ____________________
Date: ____________________	Date: ____________________

PACIFICORP

By: Andrea Kelly

Date: ____________________

Docket UE 210

REVENUE REQUIREMENT STIPULATION

Exhibit A

Results of Operations

September 25, 2009

Exhibit A

PACIFICORP UE 210

Stipulated Adjustments to Oregon Allocated Results

Year Ending December 31, 2010

($000)

Item	Adjustments	Revenue Requirement Effect
	Company Filed Revenue Requirement (non-power costs)	$92,057
S-0	**Rate of Return- 8.08% ROR**	($22,532)
S-4, S-2, S-9, and ICNU/CUB Adj.	**A&G Adjustments** Includes the revenue requirement impact of adjustments proposed by Staff and CUB/ICNU, accepted as part of the Company's Reply filing. These adjustments relate to 401k expense, insurance expense, workers compensation expense, challenge grants and FAS 112 expense. Also reflects Staff adjustments associated with uncollectibles, incentives, and insurance; Staff and ICNU/CUB adjustments associated with incentives, benefits, and pensions; and ICNU/CUB adjustments associated with wages.	($16,271)
S-5	**Distribution O&M Adjustments**	($1,230)
S-6	**Transmission O&M Adjustments and Property Taxes**	($1,619)
S-3 , S-7, S-8, S-10, S-11	**Miscellaneous Rate Base Adjustments** Reflects adjustment to rate base. Includes the revenue requirement impact of adjustments proposed by Staff and accepted as part of of the Company's Reply filing, which relate to new tariff riders (MEHC severance, Grid West, and OR Transition plan), change in allocation factors, ECD updates, and other rate base adjustments.	($8,905)
	Total Adjustments	($50,557)
	Stipulated Adjusted Revenue Requirement	$41,500

PACIFICORP UE 210
Results of Operations
Year Ending December 31, 2010
($000)

	UE 210 Oregon Results per Company Filing (1)	Stipulated Adjustments: UE 207 Transition Adjustment Mechanism (TAM) Increase (2)	Stipulated Adjustments: UE 210 General Rate Case Increase (3)	2010 Adjusted (4)	Required Change for Reasonable Return: UE 207 Transition Adjustment Mechanism (TAM) Increase (5)	Required Change for Reasonable Return: UE 210 General Rate Case Increase (6)	Results at Reasonable Return (7)
1 Operating Revenues							
2 General Business Revenues	$949,341	0	0	$949,341	$4,000	$41,500	$994,841
3 Interdepartmental	0	0	0	0	0	0	0
4 Special Sales	201,717	(2,455)	0	199,262	0	0	199,262
5 Other Operating Revenues	42,876	0	0	42,876	0	0	42,876
6 Total Operating Revenues	$1,193,934	($2,455)	$0	$1,191,479	$4,000	$41,500	$1,236,979
7 Operating Expenses							
8 Steam Production	$251,950	($1,394)	$4	$250,559	$0	$0	$250,559
9 Nuclear Production	0	0	0	0	0	0	0
10 Hydro Production	9,912	0	0	9,912	0	0	9,912
11 Other Power Supply	275,008	(18,928)	2,662	258,742	0	0	258,742
12 Transmission	51,260	1,296	(408)	52,148	0	0	52,148
13 Distribution	70,711	0	(1,163)	69,548	0	0	69,548
14 Customer Accounting	31,711	0	(554)	31,157	0	215	31,373
15 Customer Service & Info	3,695	0	0	3,695	0	0	3,695
16 Sales	0	0	0	0	0	0	0
17 Administrative & General	57,052	0	(19,602)	$37,450	0	0	$37,450
18 Total Operation & Maintenance	$751,298	($19,027)	($19,060)	$713,212	$0	$215	$713,427
19 Depreciation	$148,046	$0	($201)	$147,845	$0	$0	$147,845
20 Amortization	16,476	0	1	16,476	0	0	16,476
21 Taxes Other Than Income	51,965	0	(1,168)	50,797	0	1,053	51,849
22 Income Taxes - Federal	20,969	5,382	8,127	34,479	1,336	13,442	49,257
23 Income Taxes - State	4,470	1,193	390	6,053	182	1,827	8,061
24 Income Taxes - Def Net	17,792	0	(678)	17,114	0	0	17,114
25 Investment Tax Credit Adj.	0	0		0	0	0	0
26 Misc Revenue & Expense	(2,077)	0	0	(2,077)	0	0	(2,077)
27 Total Operating Expenses	$1,008,940	($12,451)	($12,589)	$983,900	$1,518	$16,536	$1,001,954
28 Net Operating Revenues	$184,994	$9,996	$12,589	$207,579	$2,482	$24,964	$235,025
29 Average Rate Base							
30 Electric Plant In Service	$5,550,442	$0	($35,408)	$5,515,035	$0	$0	$5,515,035
31 Plant Held for Future Use	(0)	0	0	(0)	0	0	(0)
32 Misc Deferred Debits	32,823	0	(12,689)	20,134	0	0	20,134
33 Elec Plant Acq Adj	18,568	0	0	18,568	0	0	18,568
34 Nuclear Fuel	0	0	0	0	0	0	0
35 Prepayments	12,200	0	1	12,201	0	0	12,201
36 Fuel Stock	41,007	0	0	41,008	0	0	41,008
37 Material & Supplies	49,318	0	1	49,320	0	0	49,320
38 Working Capital	12,867	0	(378)	12,489	0	0	12,489
39 Weatherization Loans	(1)	0	(0)	(1)	0	0	(1)
40 Misc Rate Base	1,206	0	0	1,206	0	0	1,206
41 Total Electric Plant	5,718,431	0	(48,472)	$5,669,960	0	0	$5,669,960
42 Less:							
43 Accum Prov For Deprec	($2,041,424)	$0	$256	($2,041,168)	$0	$0	($2,041,168)
44 Accum Prov For Amort	(141,099)	0	(6)	(141,105)	0	0	(141,105)
45 Accum Def Income Tax	(548,748)	0	(2,256)	(551,005)	0	0	(551,005)
46 Unamortized ITC	(4,172)	0	0	(4,172)	0	0	(4,172)
47 Customer Adv For Const	(3,499)	0	0	(3,499)	0	0	(3,499)
48 Customer Service Deposits	0	0	0	0	0	0	0
49 Misc Rate Base Deductions	(21,182)	0	(1)	(21,182)	0	0	(21,182)
50 Total Rate Base Deductions	(2,760,125)	0	(2,007)	($2,762,132)	0	0	($2,762,132)
							$0
51 Total Average Rate Base	$2,958,307	$0	($50,479)	$2,907,828	$0	$0	$2,907,828
52 Rate of Return	6.253%			7.139%			8.083%
53 Implied Return on Equity	6.539%			8.274%			10.125%

PACIFICORP UE 210
Stipulated Adjustments to Oregon Results
Year Ending December 31, 2010
($000)

	Rate of Return Adjustment (S-0)	A&G Adjustments (S-4, S-2, S-9, and ICNU/CUB)	Distribution O&M Adjustments (S-5)	Transmission O&M Adjustments (S-6)	Miscellaneous Rate Base Adjustments (S-3, S-7, S-8, S-10, S-11)	Total Stipulated Adjustments
1 Operating Revenues						
2 General Business Revenues	$0	$0	$0	$0	$0	$0
3 Interdepartmental	0	0	0	0	0	0
4 Special Sales	0	0	0	0	0	0
5 Other Operating Revenues	0	0	0	0	0	0
6 **Total Operating Revenues**	$0	$0	$0	$0	$0	$0
7 Operating Expenses						
8 Steam Production	$0	$0	$0	$0	$4	$4
9 Nuclear Production	0	0	0	0	0	0
10 Hydro Production	0	0	0	0	0	0
11 Other Power Supply	205	(1)	0	0	2,459	2,662
12 Transmission	0	0	0	(408)		(408)
13 Distribution	0	0	(1,163)	0	0	(1,163)
14 Customer Accounting	0	(554)	0	0	0	(554)
15 Customer Service & Info	0	0	0	0	0	0
16 Sales	0	0	0	0	0	0
17 Administrative & General	0	(14,860)	0	0	(4,742)	(19,602)
18 **Total Operation & Maintenance**	$205	($15,416)	($1,163)	($408)	($2,279)	($19,060)
19 Depreciation	$0	$0	$0	$0	($201)	($201)
20 Amortization	0	0	0	0	1	1
21 Taxes Other Than Income	0	0	0	(1,170)	2	(1,168)
22 Income Taxes - Federal	(92)	5,265	399	526	2,029	8,127
23 Income Taxes - State	(9)	377	23	77	(78)	390
24 Income Taxes - Def Net	0	0	0	0	(678)	(678)
25 Investment Tax Credit Adj.	0	0	0	0	0	0
26 Misc Revenue & Expense	0	0	0	0	0	0
27 **Total Operating Expenses**	$104	($9,773)	($741)	($976)	($1,204)	($12,589)
28 **Net Operating Revenues**	($104)	$9,773	$741	$976	$1,204	$12,589
29 Average Rate Base						
30 Electric Plant In Service	$0	$0	$0	$0	($35,408)	($35,408)
31 Plant Held for Future Use	0	0	0	0	0	0
32 Misc Deferred Debits	0	0	0	0	(12,689)	(12,689)
33 Elec Plant Acq Adj	0	0	0	0	0	0
34 Nuclear Fuel	0	0	0	0	0	0
35 Prepayments	0	0	0	0	1	1
36 Fuel Stock	0	0	0	0	0	0
37 Material & Supplies	0	0	0	0	1	1
38 Working Capital	(1)	(138)	(10)	(14)	(214)	(378)
39 Weatherization Loans	0	0	0	0	(0)	(0)
40 Misc Rate Base	0	0	0	0	0	0
41 **Total Electric Plant**	($1)	($138)	($10)	($14)	($48,309)	($48,472)
42 Less:						
43 Accum Prov For Deprec	$0	$0	$0	$0	$256	$256
44 Accum Prov For Amort	0	0	0	0	(6)	(6)
45 Accum Def Income Tax	0	0	0	0	(2,256)	(2,256)
46 Unamortized ITC	0	0	0	0	0	0
47 Customer Adv For Const	0	0	0	0	0	0
48 Customer Service Deposits	0	0	0	0	0	0
49 Misc Rate Base Deductions	0	0	0	0	(1)	(1)
50 **Total Rate Base Deductions**	$0	$0	$0	$0	($2,007)	($2,007)
51 **Total Average Rate Base**	($1)	($138)	($10)	($14)	($50,316)	($50,479)
52						
Revenue Requirement Effect	($22,532)	($16,271)	($1,230)	($1,619)	($8,905)	($50,557)

Docket UE 210

REVENUE REQUIREMENT STIPULATION

Exhibit B

Taxes

September 25, 2009

UE 210 and UE 207
Taxes Included in Rates (CY 2010)

		Oregon 2010 Normalized Results	Price Increase TAM UE 207	Price Increase GRC UE 210	Oregon 2010 Normalized Results w/Price Increases
1	**TAX CALCULATION:**				
2	Operating Revenues	1,191,479,357	4,000,000	41,500,000	1,236,979,357
3	Operating Deductions:				
4	Total O&M Expenses	713,212,111	-	215,155	713,427,267
5	Depreciation & Amortization	164,321,586	-	-	164,321,586
6	Taxes Other Than Income	50,796,868	-	1,052,507	51,849,375
7	Misc. Revenue & Expenses	(2,076,505)	-	-	(2,076,505)
8	Total Operating Deductions	926,254,060	-	1,267,662	927,521,722
9					
10	Other Deductions:				
11	Interest (AFUDC)	-	-	-	-
12	Interest (See Calc Below)	84,400,281	-	-	84,400,281
13	Schedule "M" Additions	252,520,086	-	-	252,520,086
14	Schedule "M" Deductions	289,540,060	-	-	289,540,060
15	Income Before Taxes	143,805,043	4,000,000	40,232,338	188,037,381
16					
17	State Income Taxes	6,213,462	181,600	1,826,548	8,221,610
18	State Income Tax Credit	(160,228)	-	-	(160,228)
19	**Total State Income Taxes**	**6,053,234**	**181,600**	**1,826,548**	**8,061,382**
20					
21	Total Taxable Income	137,751,809	3,818,400	38,405,790	179,975,999
22					
23	Federal Income Taxes	48,213,133	1,336,440	13,442,026	62,991,600
24	Federal Income Tax Credits	(13,734,625)	-	-	(13,734,625)
25	**Total Federal Income Taxes**	**34,478,508**	**1,336,440**	**13,442,026**	**49,256,974**
26					
27	Deferred Tax Expense:				
28	Deferred Taxes (Debit - 41010)	163,056,610	-	-	163,056,610
29	Deferred Taxes (Credit - 41110)	(145,942,505)	-	-	(145,942,505)
30	**Total Deferred Tax Expense**	**17,114,105**	-	-	**17,114,105**
31					
32	Accumulated Deferred Income Taxes:				
33	190 - Accum Def. Taxes	21,823,502	-	-	21,823,502
34	281 - Accum Def. Taxes	-	-	-	-
35	282 - Accum Def. Taxes	(561,942,966)	-	-	(561,942,966)
36	283 - Accum Def. Taxes	(10,885,187)	-	-	(10,885,187)
37	**Total Accum. Deferred Taxes**	**(551,004,650)**	-	-	**(551,004,650)**
38					
39	**Unamortized ITC Balance**	**(4,172,305)**	-	-	**(4,172,305)**
40					
41	**Interest Calculation:**				
42	Rate Base	2,907,827,703			2,907,827,703
43	Weighted Cost of Debt	2.9025%			2.9025%
44	Interest Expense	84,400,281			84,400,281

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 210

In the Matter of: PacifiCorp d/b/a Pacific Power's Request for a General Rate Increase in the Company's Oregon Annual Revenues	**RATE SPREAD AND RATE DESIGN STIPULATION**

This Rate Spread and Rate Design Stipulation ("Stipulation") is entered into for the purpose of resolving the issues among the parties to this Stipulation related to the rate spread and rate design of rates resulting from PacifiCorp's (or the "Company") revenue requirement increase in this docket. The revenue requirement increase is the subject of a separate stipulation filed by the parties to this Stipulation, with the exception of the Industrial Customers of Northwest Utilities ("ICNU").

PARTIES

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board ("CUB"), ICNU, Fred Meyer Stores and Quality Food Centers, divisions of Kroger Company ("Kroger") and the Klamath Water Users Association ("KWUA") (together, the "Parties"). The Parties represent all active participants in this docket.[1]

BACKGROUND

2. On April 2, 2009, PacifiCorp filed revised tariff sheets to be effective May 2, 2009, for Oregon that would result in a base price increase of approximately $92.1 million or 9.1 percent. PacifiCorp based its filing on a 2010 calendar year test period.

[1] Portland General Electric also intervened in this proceeding but is not a signatory to this Stipulation. PGE does not, however, oppose this Stipulation.

3. At the public meeting on April 21, 2009, the Public Utility Commission of Oregon ("Commission") suspended the Company's application for revised tariff sheets for a period of nine months. Based on the suspension, the effective date of the revised tariff sheets would be February 2, 2010.

4. Pursuant to Administrative Law Judges Wallace's and Hardie's Prehearing Conference Memorandum of April 22, 2009, the parties to this docket convened a settlement conference on June 24, 2009. The parties held additional settlement conferences on August 20 and September 10, 2009. The settlement conferences were noticed and all parties were invited to participate.

5. As a result of the settlement conferences, the Parties have reached a settlement in this case resolving all issues related to rate spread and rate design. Pursuant to a separate Revenue Requirement Stipulation, the Parties with the exception of ICNU reached a settlement resolving all issues related to revenue requirement. This Stipulation describes the rate spread and rate design for the revenue requirement in this case. The effective date of these new rates is February 2, 2010.

AGREEMENT

6. The Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Parties agree that the stipulated rate spread and rate design produces rates that are fair, just, and reasonable.

7. Rate Spread. The Parties agree to apply the net rate increase factors shown below to the overall general rate case net rate percentage increase for each rate schedule class. Net rates include the effect of all tariff riders. For illustrative purposes, Exhibit A demonstrates the agreed-upon rate spread in this case based upon the Revenue Requirement Stipulation.

Rate Schedule		Net Rate Increase Factor
Residential	4	76.8%
General Service		
Gen. Svc. < 31 kW	23	147%
Gen. Svc. 31 - 200 kW	28	124%
Gen. Svc. 201 - 999 kW	30	123%
Partial Requirements Service >= 1,000 kW	47	117%
Large General Service >= 1,000 kW	48	117%
Agricultural Pumping Service	41	117%
Public Street Lighting		117%

8. Rate Design.

a. Residential Basic Charge. The Parties agree to increase the residential basic charge from $7.50 per month to $8.00 per month.

b. Schedule 200 Rate Design. The Parties agree to change the present Schedule 200 Supply Service rate design. The Parties agree that the proposed Schedule 200 Supply Service rate design will be non-bypassable to direct access customers and will not be subtracted in the calculation of the Transition Adjustment. In addition, the Schedule 201 rate design as proposed by the Company will be allowed to go into effect and will be bypassable to direct access customers. The rate design for proposed Schedule 200 applicable to delivery service Schedules 30, 47, and 48 will be changed from its present energy only cents per kWh rate design to a two-part rate design which includes a demand charge equal to $1.00 per billing kW (as defined in the respective tariffs) plus a cents per kWh energy charge. Schedule 200 rates will go into effect on January 1, 2010, as described in the Stipulation in UE 207.

c. General. With the exception of the items listed above, the Parties agree to the rate design in the Company's filing in this case.

9. Tariff. Upon approval of this Stipulation and the Revenue Requirement Stipulation filed in this proceeding, PacifiCorp will file its revised tariff sheets and new tariff riders as a compliance filing in Docket UE 210, effective February 2, 2010. The tariff sheets and new tariff riders will reflect rates designed as agreed in this Stipulation.

10. Rate Mitigation Adjustment ("RMA"). If PacifiCorp files a stand-alone Transition Adjustment Mechanism ("TAM") prior to the filing of its next general rate case, and if the TAM could produce a rate decrease, the Parties agree that they may address the level of the RMA in that TAM.

11. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. 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.

12. 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.

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

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

This Stipulation is entered into by each party on the date entered below such Party's signature.

STAFF	CUB
By: ______	By: ______
Date: 9/25/9	Date: ______
KROGER	ICNU
By: ______	By: ______
Date: ______	Date: ______
KWUA	PACIFICORP
By: ______	By: ______
Date: ______	Date: ______

This Stipulation is entered into by each party on the date entered below such Party's signature.

STAFF

By: ______________________________

Date: ______________________________

CUB

By: ______________________________

Date: 9-25-09

KROGER

By: ______________________________

Date: ______________________________

ICNU

By: ______________________________

Date: ______________________________

KWUA

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: ______________________________

This Stipulation is entered into by each party on the date entered below such Party's signature.

STAFF	CUB
By: ______________	By: ______________
Date: ______________	Date: ______________
KROGER K Boehm	ICNU
By: Kurt J. Boehm	By: ______________
Date: 9-25-09	Date: ______________
KWUA	PACIFICORP
By: ______________	By: ______________
Date: ______________	Date: ______________

This Stipulation is entered into by each party on the date entered below such Party's signature.

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

KROGER

By: ______________________

Date: ______________________

ICNU

By: Irion Sanger

Date: Sept 25 2009

KWUA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

This Stipulation is entered into by each party on the date entered below such Party's signature.

STAFF	CUB
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________
KROGER	ICNU
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________
KWUA	PACIFICORP
By: Greg Addington	By: ______________________
Date: 9/25/09	Date: ______________________

This Stipulation is entered into by each party on the date entered below such Party's signature.

STAFF	CUB
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________
KROGER	ICNU
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________
KWUA	PACIFICORP
By: ______________________	By: Andrea Kelly
Date: ______________________	Date: ______________________

Docket UE 210

RATE SPREAD AND DESIGN STIPULATION

Exhibit A

September 25, 2009

ORDER NO. 10-022

Exhibit A - Page 1 of 3

PACIFIC POWER & LIGHT COMPANY
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates[1]	Present Revenues ($000) Adders[2]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[2]	Proposed Revenues ($000) Net Rates	Change Base Rates ($000)	Change Base Rates ¢/kWh[3]	Change Base Rates %[3]	Change Net Rates ($000)	Change Net Rates ¢/kWh[3]	Change Net Rates %[3]	Factor	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)		
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(5)	(12)/(6)	(11) - (8)	(15)/(5)	(15)/(8)		
	Residential																		
1	Residential	4	4	478,485	5,435,846	$473,282	$18,970	$492,252	$483,818	$25,928	$509,746	$10,536	0.194	2.2%	$17,494	0.322	3.6%	76.8%	1
2	**Total Residential**			478,485	5,435,846	$473,282	$18,970	$492,252	$483,818	$25,928	$509,746	$10,536		2.2%	$17,494		3.6%		2
	Commercial & Industrial																		
3	Gen. Svc. < 31 kW	23	23	74,055	1,013,941	$91,209	($2,688)	$88,521	$94,009	$517	$94,526	$2,800	0.276	3.1%	$6,005	0.592	6.8%	147%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,101	2,045,065	$126,124	$14,255	$140,379	$135,081	$13,314	$148,395	$8,957	0.438	7.1%	$8,016	0.392	5.7%	124%	4
5	Gen. Svc. 201 - 999 kW	30	30	853	1,378,646	$79,102	$6,369	$85,471	$84,595	$5,721	$90,316	$5,493	0.398	6.9%	$4,845	0.351	5.7%	123%	5
6	Large General Service >= 1,000 kW	48	48	215	2,643,901	$131,448	$3,542	$134,990	$142,594	($236)	$142,358	$11,146	0.415	8.5%	$7,368	0.272	5.4%	117%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	571,965	$25,876	$767	$26,643	$28,067	($51)	$28,016	$2,191	0.415	8.5%	$1,373	0.272	5.4%	117%	7
8	Agricultural Pumping Service	41	41	6,108	136,792	$14,365	($3,071)	$11,294	$14,758	($2,852)	$11,906	$393	0.287	2.7%	$612	0.447	5.4%	117%	8
9	Agricultural Pumping - Other	33	33	2,062	118,046	$3,839	$344	$4,183	$3,609	$385	$3,994	($230)	(0.195)	-6.0%	($189)	(0.160)	-4.5%		9
10	**Total Commercial & Industrial**			93,401	7,908,356	$471,963	$19,518	$491,481	$502,713	$16,798	$519,511	$30,750		6.5%	$28,030		5.7%		10
	Lighting																		
11	Outdoor Area Lighting Service	15	15	7,404	10,466	$1,314	$132	$1,446	$1,375	$149	$1,524	$61	0.583	4.6%	$78	0.745	5.4%		11
12	Street Lighting Service	50	50	287	10,738	$1,173	$124	$1,297	$1,212	$155	$1,367	$39	0.363	3.3%	$70	0.652	5.4%		12
13	Street Lighting Service HPS	51	51	686	16,085	$2,833	$270	$3,103	$2,928	$343	$3,271	$95	0.591	3.4%	$168	1.044	5.4%		13
14	Street Lighting Service	52	52	79	1,186	$134	$14	$148	$139	$17	$156	$5	0.422	3.7%	$8	0.675	5.4%		14
15	Street Lighting Service	53	53	250	9,316	$591	$75	$666	$611	$91	$702	$20	0.215	3.4%	$36	0.386	5.4%		15
16	Recreational Field Lighting	54	54	105	816	$70	$6	$76	$72	$8	$80	$2	0.245	2.9%	$4	0.490	5.3%		16
17	**Total Public Street Lighting**			8,811	48,607	$6,115	$621	$6,736	$6,337	$763	$7,100	$222		3.6%	$364		5.4%	117%	17
18	**Total Sales to Ultimate Consumers**			580,697	13,392,809	$951,360	$39,109	$990,469	$992,868	$43,489	$1,036,357	$41,508		4.4%	$45,888		4.6%		18
19	**Employee Discount**				18,481	($397)	($16)	($413)	($407)	($22)	($429)	($10)			($16)				19
20	**Total Sales with Employee Discount**			580,697	13,392,809	$950,963	$39,093	$990,056	$992,461	$43,467	$1,035,928	$41,498		4.4%	$45,872		4.6%		20
21	AGA Revenue					$2,380		$2,380	$2,380		$2,380	$0			$0				21
22	**Total Sales with Employee Discount and AGA**			580,697	13,392,809	$953,343	$39,093	$992,436	$994,841	$43,467	$1,038,308	$41,498		4.4%	$45,872		4.6%		22

[1] Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

[2] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[3] Percentages and per kilowatt-hour rates shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Exhibit A - Page 2 of 3

PACIFIC POWER & LIGHT COMPANY
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	Pre Sch No.	Pro Sch No.	Indep. Eval. 93 (000)	Prop. Sales 96 (000)	Interv. Fndg. 97 (000)	Tax Adj 102 (000)	OR Trns Plan 193 (000)	MEHC Sev 194 (000)	Grid West 195 (000)	RAC Defer. 203 (000)	Shop. Inctv. 296 (000)	RMA 299 (000)	RMA 299 (000)	Total (000)	Total (000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) PRO	(9) PRO	(10) PRO	(11)	(12)	(13) PRE	(14) PRO	(15) PRE	(16) PRO
	Residential															
1	Residential	4	4	$381	($544)	$0	$10,817	$815	$870	$163	$5,218	$0	$3,098	$8,208	$18,970	$25,928
2	**Total Residential**															
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	$71	($101)	$0	$2,017	$152	$163	$31	$993	$0	($5,668)	($2,809)	($2,688)	$517
4	Gen. Svc. 31 - 200 kW	28	28	$144	($205)	$0	$4,070	$307	$327	$61	$1,963	$82	$8,201	$6,565	$14,255	$13,314
5	Gen. Svc. 201 - 999 kW	30	30	$96	($138)	$0	$2,744	$207	$221	$41	$1,296	$55	$2,316	$1,199	$6,369	$5,721
6	Large General Service >= 1,000 kW	48	48	$185	($264)	$0	$5,261	$397	$424	$80	$2,300	$0	($3,940)	($8,619)	$3,542	($236)
7	Partial Req. Svc. >= 1,000 kW	47	47	$40	($57)	$0	$1,138	$86	$92	$17	$498	$0	($852)	($1,865)	$767	($51)
8	Agricultural Pumping Service	41	41	$10	($14)	$0	$272	$21	$22	$4	$131	$3	($3,473)	($3,301)	($3,071)	($2,852)
9	Agricultural Pumping - Other	33	33	$8	($12)	$0	$235	$18	$19	$4	$113	$0	$0	$0	$344	$385
10	**Total Commercial & Industrial**			$554	($791)	$0	$15,737	$1,188	$1,268	$238	$7,294	$140	($3,416)	($8,830)	$19,518	$16,798
	Lighting															
11	Outdoor Area Lighting Service	15	15	$1	($1)	$0	$22	$1	$1	$0	$5	$0	$105	$120	$132	$149
12	Street Lighting Service	50	50	$1	($1)	$0	$21	$2	$2	$0	$5	$0	$98	$125	$124	$155
13	Street Lighting Service HPS	51	51	$1	($2)	$0	$32	$2	$3	$0	$11	$0	$228	$296	$270	$343
14	Street Lighting Service	52	52	$0	$0	$0	$2	$0	$0	$0	$1	$0	$11	$14	$14	$17
15	Street Lighting Service	53	53	$1	($1)	$0	$19	$1	$1	$0	$2	$0	$54	$68	$75	$91
16	Recreational Field Lighting	54	54	$0	$0	$0	$2	$0	$0	$0	$0	$0	$4	$6	$6	$8
17	**Total Public Street Lighting**			$4	($5)	$0	$98	$6	$7	$0	$24	$0	$500	$629	$621	$763
18	**Total**			$939	($1,340)	$0	$26,652	$2,009	$2,145	$401	$12,536	$140	$182	$7	$39,109	$43,489
19	**Employee Discount**			$0	$0	$0	($9)	($1)	($1)	$0	($4)	$0	($3)	($7)	($16)	($22)
20	**Total Sales with Employee Discount**			$939	($1,340)	$0	$26,643	$2,008	$2,144	$401	$12,532	$140	$179	$0	$39,093	$43,467

Exhibit A - Page 3 of 3

PACIFIC POWER & LIGHT COMPANY
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	Pre Sch No.	Pro Sch No.	Indep. Eval. 93 ¢/kWh	Prop. Sales 96 ¢/kWh	Interv. Fndg. 97 ¢/kWh	Tax Adj 102 ¢/kWh	OR Trns Plan 193 ¢/kWh	MEHC Sev 194 ¢/kWh	Grid West 195 ¢/kWh	RAC Defer. 203 ¢/kWh	Shop. Inctv. 296 ¢/kWh	RMA 299 ¢/kWh	RMA 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) PRO	(9) PRO	(10) PRO	(11)	(12)	(13) PRE	(14) PRO
	Residential													
1	Residential	4	4	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.096	0.000	0.057	0.151
	Commercial & Industrial													
2	Gen. Svc. < 31 kW	23	23	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.098	0.000	(0.559)	(0.277)
3	Gen. Svc. 31 - 200 kW	28	28	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.096	0.004	0.401	0.321
4	Gen. Svc. 201 - 999 kW	30	30	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.094	0.004	0.168	0.087
5	Large General Service >= 1,000 kW	48	48	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.087	0.000	(0.149)	(0.326)
6	Partial Req. Svc. >= 1,000 kW	47	47	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.087	0.000	(0.149)	(0.326)
7	Agricultural Pumping Service	41	41	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.096	0.004	(2.539)	(2.413)
8	Agricultural Pumping - Other	33	33	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.096	0.000	0.000	0.000
	Lighting													
9	Outdoor Area Lighting Service	15	15	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.053	0.000	1.002	1.150
10	Street Lighting Service	50	50	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.044	0.000	0.908	1.160
11	Street Lighting Service HPS	51	51	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.069	0.000	1.416	1.840
12	Street Lighting Service	52	52	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.053	0.000	0.920	1.200
13	Street Lighting Service	53	53	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.023	0.000	0.580	0.725
14	Recreational Field Lighting	54	54	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.039	0.000	0.539	0.760