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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 13-04-012 (Filed April 18, 2013)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2014 GENERAL RATE CASE

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I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), the parties to this Settlement Agreement (Settling Parties) agree on a mutually acceptable outcome to the marginal cost and revenue allocation issues in the proceeding captioned above. The details of this Marginal Cost and Revenue Allocation (MC/RA) Settlement Agreement are set forth herein.

This MC/RA Settlement Agreement is a direct result of Administrative Law Judge (ALJ) Douglas Long and Assigned Commissioner Michael Peevey's encouragement to the active parties to meet and seek a workable compromise. The active parties hold differing views on numerous aspects of PG&E's initial marginal cost and revenue allocation proposals in Phase II of this General Rate Case (GRC) proceeding. However the Parties bargained earnestly and in good faith to seek a compromise and to develop this MC/RA Settlement Agreement, which is the product of arms-length negotiations among the Settling Parties on a number of disputed issues. These negotiations considered the interests of all of the active parties on marginal cost and revenue allocation issues, and the MC/RA Settlement Agreement addresses each of these interests in a fair and balanced manner.

The Settling Parties developed this MC/RA Settlement Agreement by mutually accepting concessions and trade-offs among themselves. Thus, the various elements and sections of this

MC/RA Settlement Agreement are intimately interrelated, and should not be altered, as the Settling Parties intend that this Settlement Agreement be treated as a package solution that strives to balance and align the interests of each party. Accordingly, the Settling Parties respectfully request that the Commission promptly approve the MC/RA Settlement Agreement without modification. Any material change to the MC/RA Settlement Agreement shall render it null and void, unless all of the Settling Parties agree in writing to such changes.

II. SETTLING PARTIES

The Settling Parties are as follows[1/]:

- Agricultural Energy Consumers Association (AECA);
- California City-County Street Light Association (CAL-SLA);
- California Farm Bureau Federation (CFBF);
- California Large Energy Consumers Association (CLECA);
- California League of Food Processors (CLFP);
- California Manufacturers & Technology Association (CMTA);
- Direct Access Customer Coalition (DACC);
- Energy Producers and Users Coalition (EPUC);
- Energy Users Forum (EUF);
- Federal Executive Agencies (FEA);
- Office of Ratepayer Advocates (ORA);
- Pacific Gas and Electric Company (PG&E);
- Small Business Utility Advocates (SBUA);
- The Utility Reform Network (TURN); and
- Western Manufactured Housing Communities Association (WMA).

1/ Although the following parties have not joined the MC/RA Settlement Agreement, they have, nonetheless, affirmatively indicated that they do not oppose the MC/RA Settlement Agreement as presented herein: City and County of San Francisco (CCSF), Marin Clean Energy (MCE), Solar Energy Industries Association (SEIA), California Solar Energy Industries Association (CALSEIA), and the Modesto and Merced Irrigation Districts (MMID).

III. SETTLEMENT CONDITIONS

This MC/RA Settlement Agreement resolves the issues raised by the Settling Parties in A.13-04-012 (Phase II), on marginal costs and revenue allocation, subject to the conditions set forth below:

1. This MC/RA Settlement Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters.
2. This MC/RA Settlement Agreement represents a negotiated compromise among the Settling Parties' respective litigation positions on the matters described, and the Settling Parties have assented to the terms of the MC/RA Settlement Agreement only to arrive at the agreement embodied herein. Nothing contained in the MC/RA Settlement Agreement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the Settling Parties on these matters in this proceeding.
3. This MC/RA Settlement Agreement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding.
4. The Settling Parties agree that this MC/RA Settlement Agreement is reasonable in light of the testimony submitted, consistent with the law, and in the public interest.
5. The Settling Parties agree that the language in all provisions of this MC/RA Settlement Agreement shall be construed according to its fair meaning and not for or against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
6. The Settling Parties agree that this MC/RA Settlement Agreement addresses all marginal cost and revenue allocation issues.
7. This MC/RA Settlement Agreement may be amended or changed only by a written agreement signed by the Settling Parties.
8. The Settling Parties shall jointly request Commission approval of this MC/RA Settlement Agreement and shall actively support its prompt approval. Active support shall include

written and/or oral testimony (if testimony is required), briefing (if briefing is required), comments and reply comments on the proposed decision,[2/] advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

9. The Settling Parties intend the MC/RA Settlement Agreement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this MC/RA Settlement Agreement, the Settling Parties reserve their rights under Rule 12 of the CPUC's Rules of Practice and Procedure, and the MC/RA Settlement Agreement should not be admitted into evidence in this or any other proceeding.

IV. OVERALL PROCEDURAL HISTORY

On January 24, 2013, PG&E requested, and the CPUC approved, a two-month extension of time to file its Application in Phase II of the 2014 GRC. The extension revised the filing date from February 13, 2013 (as required under the CPUC's Rate Case Plan) to April 18, 2013.

On April 18, 2013, PG&E filed A.13-04-012, related to electric marginal costs, revenue allocation, and rate design. As set forth at page 1 of that application, PG&E's marginal cost, revenue allocation and rate design proposals were intended:

> [T]o make progress in moving electric rates closer to cost of service, in order to send more economically efficient price signals and promote more equitable treatment among all customers. At the same time, PG&E balances other objectives including customer acceptance, rate stability, and simplifying electric rates to make them easier for customers to understand.

The application was protested on May 20, 2013, by ORA, TURN, Greenlining/CforAT, AECA/CFBF, and MCE.

A prehearing conference was held on June 3, 2013, before ALJ Long. The scope of issues and procedural schedule were set forth in the Assigned Commissioner's Scoping Memorandum and Ruling dated July 12, 2013 (Scoping Memo). Per the Scoping Memo, PG&E's updated testimony required under the CPUC's Rate Case Plan was due on August 2,

2/ Any oral and written testimony that the CPUC might require may be prepared and submitted jointly among parties with similar interests.

2013. On July 26, 2013, at PG&E's request, ALJ Long granted a two-week extension of that filing date. On August 16, 2013, PG&E updated its showing on marginal costs, revenue allocation, and rate design.

In a ruling issued October 18, 2013, ALJ Long modified the scope of A.13-04-012 to suspend work on residential rate design in anticipation that residential rate design issues would be considered in the Residential Rate Reform Order Instituting Rulemaking (RROIR, R.12-06-013), in which the CPUC would be examining and modifying residential rate structures in accordance with Assembly Bill (AB) 327.[3/] On Wednesday, November 6, 2013, ALJ Long clarified that electric master meter discounts and gas baseline quantities would not be suspended but rather would remain within the scope of GRC Phase II. On November 8, 2013, PG&E issued a notice of availability of revenue allocation and rate design models that were consistent with the suspension and deferral of residential electric rate design.

ORA served its prepared testimony on November 15, 2013, on marginal cost, revenue allocation, non-residential rate design, and residential electric master meter discounts. On December 13, 2013, fifteen intervenors (AECA, CAL-SLA, CFBF, CLECA/CMTA, CCSF, DACC, EUF, EPUC, FEA, MMID, MCE, SBUA, SEIA, TURN, and WMA) served their prepared testimony. On January 17, 2014, ALJ Long issued a ruling granting the parties' joint request for a continuance in the original schedule for Phase II of PG&E's 2014 GRC, in recognition of the parties' ongoing efforts to seek settlement, as discussed below.

V. SETTLEMENT HISTORY

Pursuant to Rule 12 of the CPUC's Rules of Practice and Procedure, on January 9, 2014, PG&E served on all parties a notice of a settlement conference to be held January 17, 2014. Immediately after that settlement conference, PG&E on behalf of the parties, emailed a request to the ALJ, and ALJ Long promptly issued an email ruling on January 17, 2014, granting the parties' request for a continuance in the schedule to allow for further settlement conferences, with settlement status reports to be filed on February 14 and March 12, 2014. On March 20, and

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3/ The CPUC, accordingly, re-categorized the RROIR as a ratesetting proceeding in January 2014.

on May 21, 2014, ALJ Long granted further continuances in the schedule to allow the parties time for additional work on settlement of issues in this proceeding.

On March 13, 2014, the parties participating in settlement discussions reached an agreement in principle on the terms of this MC/RA Settlement Agreement. On March 20, 2014, PG&E orally notified ALJ Long that the active parties to the proceeding had reached settlement in principle regarding marginal cost and revenue allocation-related issues. As part of the joint settlement status reports filed in this proceeding, PG&E informed ALJ Long that the parties were continuing separate settlement discussions among sub-groups of parties interested in the remaining GRC Phase II issues, as discussed in Section VI below.

VI. SETTLEMENT TERMS

Considering and both recognizing and compromising the litigation positions taken by the individual parties, the Settling Parties agree to the revenue allocation set forth in this MC/RA Settlement Agreement. The revenue allocation amounts, percentages, and procedures agreed to in this MC/RA Settlement Agreement are reasonable and based on the record in this proceeding.

No later than July 25, 2014, PG&E and ORA will jointly serve a comparison exhibit showing the impact of the MC/RA Settlement Agreement in relation to their respective litigation positions, as required by Rule 12.1(a).

The Settling Parties agree that all testimony served prior to the date of this MC/RA Settlement Agreement that addresses the issues resolved by this MC/RA Settlement Agreement should be admitted into evidence without cross-examination by the Settling Parties.

The Settling Parties further agree to try to reach agreement on additional issues in A.13-04-012 including the remaining residential rate design issues and the non-residential rate design issues that are not resolved by this MC/RA Settlement Agreement.[4/] To the extent all of those rate design issues are not ultimately settled, the Settling Parties agree to pursue litigation in this

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4/ PG&E is still conducting separate settlement discussions in the areas of: (1) small and medium commercial rate design, (2) large commercial and industrial rate design (including standby), (3) agricultural rate design, (4) streetlight rate design, (5) rates for Schedule E-Credit, and (6) limited residential rate design issues not being considered in the RROIR. If and as settlements are reached on such rate design issues, they will be submitted as supplements to this Settlement, as was done in PG&E's 2011 GRC Phase II proceeding.

proceeding on those rate design issues only, provided those issues do not affect the outcome of issues agreed upon in this MC/RA Settlement Agreement.

The Settling Parties agree that Agricultural party proposals relating to aggregation of accounts and Public Utilities Code § 744(c)'s potential requirements, as well as adjustments for the transfer of customers from flat rates to Time-Of-Use (TOU) rates, will be removed from revenue allocation discussions in this proceeding. These items will be included among the other issues to be considered in the Agricultural rate design settlement discussions, and shall be resolved in such a way as not to have revenue allocation implications when combined with other agricultural rate design changes. Specifically, any revenue loss from the transfer of customers to TOU rates or from any load aggregation proposals that may be adopted will not result in inter-class revenue transfers. The details of how this will be accomplished will be addressed with the Agricultural rate design in this proceeding.

VII. MARGINAL COSTS SETTLEMENT

This MC/RA Settlement Agreement does not adopt any of the Settling Parties' marginal cost principles or proposals as the basis for the Revenue Allocation settlement described in Section VIII below. The Settling Parties agree that this MC/RA Settlement Agreement addresses all necessary marginal cost issues including the specific marginal costs to be used solely for the purpose of establishing costs where needed for customer specific contract analysis including as required by Schedule E-31 and for analysis of contribution to margin for customers taking service under Schedule EDR. The marginal costs to be used for these analyses are provided in Appendix A to this MC/RA Settlement Agreement. Nothing in this MC/RA Settlement Agreement shall preclude any Settling Party from advocating for its preferred marginal costs in any other Commission proceeding or for the purpose of addressing specific rate design issues yet to be considered in this or other rate design proceedings.

If the Commission were to adopt new marginal costs/methodologies, the marginal cost values generated by such new methodologies shall not be used for the purpose of changing the agreed revenue allocation, as set forth in this MC/RA Settlement Agreement.

VIII. REVENUE ALLOCATION SETTLEMENT

1. Revenue Allocation Principles for the Phase II Allocation

The Settling Parties agree that electric revenue should be allocated as a result of A.13-04-012 on an overall revenue-neutral basis to preserve then-required total authorized revenue. The Settling Parties agree to the Phase II revenue allocation to be implemented as a result of this proceeding as set forth in the following Table 1. Table 1 shows the electric revenue based on present rates used to prepare this Settlement, the electric revenue that results from the Settlement, and the percentage change for both bundled and Direct Access/Community Choice Aggregation (DA/CCA) customers. The Settling Parties agree that upon implementation PG&E will target the average percentage change for every customer group shown in Table 1, but the actual results may vary based on rate and sales changes that will occur before this MC/RA Settlement Agreement is implemented. The Settling Parties agree as follows:

a. The revenue allocation percentages shown in Table 1 establish the basis for the Phase II allocation resulting from this proceeding.

b. The parties agree that rate design changes that may be considered in future settlements in this proceeding will be designed so as not to result in projected revenue shortfalls from any class. This provision includes, but is not limited to, agricultural account aggregation and any additional transition of agricultural customers from flat to TOU rates.

c. There is no agreement on the specific marginal cost values for purposes of revenue allocation.

d. There is no change to the allocation of Nuclear Decommissioning, the Department of Water Resources (DWR) bond charge, the Energy Costs Recovery Amount, the New System Generation Charge (NSGC), Greenhouse Gas Allowance Return, the Competition Transition Charge (CTC), or, for DA/CCA customers, the Power Charge Indifference Adjustment (PCIA).

e. Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the FERC.

f. There is no change to the allocation of Public Purpose Program (PPP) rates except due to the recalculation of the cost of the CARE discount. PPP rates will be developed as the sum of public purpose program components:

1. The cost of the CARE discount will be determined based on the difference between CARE and non-CARE rates excluding the CARE surcharge, the California Solar Initiative cost, and the DWR bond charge. This cost will be allocated to eligible customers on an equal cents per kWh basis and collected through the CARE surcharge component of PPP rates. This requires an iterative determination of the CARE surcharge in PG&E's revenue allocation and rate design model.
2. There is no change to the methodology for setting rates for the remaining public purpose program components for the Phase II allocation.

g. After the allocations of all the revenues described above have been determined, PG&E will seek to create the following bundled and DA/CCA percentage changes agreed to in this proceeding by implementing the following three steps:

Step 1: For each customer class, set the bundled increase not to exceed 0.95 percent and the bundled decrease not to be less than -0.78 percent. For each customer class, set the DA/CCA increase not to exceed 2.60 percent and the DA/CCA decrease not to be less than -1.40 percent. In addition, the bundled residential increase will be limited to 0.50 percent. The revenue allocation mitigation methodology shall be consistent with that set forth in Exhibit PG&E-4, p. 2-12, line 11 through p. 2-13, line 2, modified to substitute the agreed limits on increases and decreases set forth above.

Step 2: At the time this agreement was signed, PG&E's revenue allocation and rate design model showed that the above limits on increases and decreases would result in full collection of PG&E's revenue based on the assumptions used in the model at that time. However, if at the time this Settlement is implemented, the use of these agreed limitations results in revenue adjustments that do not add to zero (i.e., do not collect the then-required revenue), PG&E shall allow the DA/CCA class level revenue for E-19 to adjust so that any revenue changes necessary to collect the then-required revenue are taken up by that class, provided however, the change to the DA/CCA class level revenue to E-19 is as small as reasonably possible and does not exceed the cap or floor. Similarly, for bundled customers, any necessary revenue changes necessary to collect the then-required revenue would be taken up by the residential class whose change should also be as small as reasonably possible and not exceed the cap or floor. Should these adjustments not be sufficient to collect the then-required revenue, further adjustments will be made to the revenue for all classes as necessary to collect the then-required revenue and will be as small as reasonably possible.[5/]

Step 3: As a final step, once the model is able to fully collect the then-required revenue, if the solution results in a rate increase to the bundled residential class of more than 0.50 percent, all bundled percentage changes will be increased by an identical amount until this increase is equal to the amount that the residential increase is over 0.50 percent. For example, a bundled increase not to exceed 0.98 percent for the Streetlighting and Agricultural classes, a bundled decrease not to be less than -0.75 percent for the Small, Medium, E-19, E-20 and Standby customer classes, and a bundled increase of 0.53 percent for the Residential class would result in an increase of 0.03 percent above the agreed upon level for all classes.

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5/ Step 2 would not be required if the then-required revenue is fully collected in Step 1.

Table 1
Pacific Gas and Electric Company Phase II
Settlement Revenue Allocation Results

Bundled Class	Total Revenue at Present Rates[1]	Total Revenue at Proposed Rates	Percent Change
Residential	$5,309,098,010	$5,335,623,998	0.50%
Small Light & Power	$1,613,868,527	$1,601,320,699	-0.78%
Medium Light & Power	$1,239,640,531	$1,230,002,326	-0.78%
E-19	$1,816,293,284	$1,802,171,604	-0.78%
Streetlight	$69,901,669	$70,565,734	0.95%
Standby	$57,392,554	$56,946,327	-0.78%
Agricultural	$864,359,596	$872,571,013	0.95%
E-20T	$368,809,086	$365,941,596	-0.78%
E-20P	$577,978,010	$573,484,231	-0.78%
E-20S	$231,273,602	$229,478,926	-0.78%
Total Bundled	$12,148,614,871	$12,138,106,453	-0.09%

DA/CCA Class	Total Revenue at Present Rates[1]	Total Revenue at Proposed Rates	Percent Change
Residential	$85,603,947	$84,405,491	-1.40%
Small Light & Power	$32,281,647	$31,829,704	-1.40%
Medium Light & Power	$53,964,217	$55,367,287	2.60%
E-19	$223,887,070	$228,173,886	1.91%
Streetlight	$887,638	$910,716	2.60%
Standby	$1,707,723	$1,683,818	-1.40%
Agricultural	$3,111,140	$3,192,029	2.60%
E-20T	$50,464,260	$51,645,799	2.34%
E-20P	$121,563,706	$124,721,565	2.60%
E-20S	$44,386,361	$45,529,739	2.58%
FPP T[2]	$3,336,837	$3,554,126	6.51%
FPP P[2]	$196,285	$204,185	4.02%
FPP S[2]	$1,727,634	$1,783,220	3.22%
Total DA/CCA	$623,118,465	$633,001,568	1.59%
(1) Present rate revenue is based on rates effective May 1, 2013.			
(2) FPP revenue is combined with E-20, by voltage, for application of caps and floors.			

2. Timing of the Phase II Rate Change

If the rate change pursuant to this MC/RA Settlement Agreement occurs in 2014, it shall be based on the sales forecast utilized in the 2014 Energy Resource Recovery Account (ERRA) forecast proceeding in accordance with D. 13-12-043, which decided A.13-05-015. If the rate change pursuant to this MC/RA Settlement Agreement is not implemented until January 1, 2015, the rate change on January 1, 2015, will be conducted in two steps: (1) allocation pursuant to this agreement based on the 2014 sales forecast; and then (2) allocation of revised revenue requirements pursuant to the 2015 Annual Electric True-Up (AET), based on the 2015 sales forecast and the guidelines set forth in Section 3 below, regarding Rate Changes Between General Rate Cases. If the rate change implementing this MC/RA Settlement Agreement does not occur until after January 1, 2015, PG&E will incorporate the MC/RA Settlement Agreement into rates based on then-current rates and the 2015 sales forecast.

3. Rate Changes Between General Rate Cases

After rates are implemented pursuant to the MC/RA Settlement Agreement and the Commission's decision in A.13-04-012, rates will be changed to reflect changes in the revenue requirement in the manner set forth below, until the effective date of implementation of a decision in Phase II of PG&E's next GRC proceeding:

a. Revenue requirement changes between GRCs will be identified by function (e.g., nuclear decommissioning, generation, etc.). Each customer class and schedule will be allocated the average percentage change in functional revenue necessary to collect the functional revenue requirement. This approach to allocating costs using a system average percentage change by function will be employed such that each customer group's share of each functional revenue requirement remains approximately the same. For schedules that are designed together, such as schedules that are designed on a revenue neutral basis, the system average percentage change by function will be applied to the combined rate design group.

b. Generation revenue developed to determine the appropriate starting point to apply the percentages from Section 3 (a) above will exclude directly assigned revenue (i.e., other standby revenue). For the rate changes where there is a change to CTC, current generation revenue used for purposes of allocation will be determined after the change to CTC is incorporated, consistent with current practice.[6/]

c. The 100 peak hour allocation factors for CTC will be revised each year based on the most recent available information at the time PG&E files its annual ERRA forecast application consistent with current practice. The NSGC and, for DA/CCA customers, the PCIA will be developed consistent with current practice.

d. Distribution revenue developed to determine the appropriate starting point to apply the percentages from Section 3(a) above will exclude directly assigned revenue (including, but not limited to, other standby revenue, E-BIP discounts, streetlight facilities charges, meter charges, employee discounts, and the Schedule A-15 facilities charge) as well as estimated California Alternate Rates for Energy (CARE) program discounts.

e. PPP rates will be developed as the sum of three pieces and will be allocated as follows:

   1. The cost of the CARE program will be determined and the CARE surcharge will be set once per year in the Annual Electric True-Up (AET) proceeding based on the difference between CARE and non-CARE rates excluding the CARE surcharge, the CSI and the DWR Bond charge. The cost will be allocated to eligible customers on an equal cents per kWh basis and collected through the CARE surcharge component of PPP rates.

   2. The cost of the Low Income Energy Efficiency and Procurement Energy Efficiency will be allocated to customers based on an equal percent of the sum of then-required Low Income Energy Efficiency and Procurement Energy Efficiency revenue (that is, the same percentage will be applied to the then-required revenue for each customer group to determine the allocated revenue).

   3. PG&E will allocate revenues for the Electric Program Investment Charge (EPIC) and Former Energy Efficiency Public Goods Charge (PGC-EE) based on an equal

6/ In addition, generation adjustments for SmartRate™ and Peak Day Pricing will be deducted from the generation revenue to be allocated as approved by the Commission.

percent of the sum of then-current revenue for these items.

f. Rate design for residential rate changes between GRCs will be dictated by the Commission's decisions in the RROIR (R.12-06-013), the proceeding in which the Commission i examining and reforming residential rate structures.

g. Non-residential rate changes will be implemented as equal percentage changes to demand and energy charges by component as necessary to collect the assigned revenue. Customer charges, streetlight facilities charges, meter charges, and minimum charges will be unchanged between general rate cases,[7/] unless otherwise specified in a Commission decision in this 2014 GRC Phase II, or revised by a separate decision (for example, in a PG&E Rate Design Window proceeding).

h. The DWR Bond charge, the Energy Cost Recovery Amount and Nuclear Decommissioning charge shall continue to be collected on an equal cents per kWh basis for all eligible customers.

i. Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the FERC.

j. Greenhouse gas allowance returns will be set as specified separately by the CPUC.

k. PG&E will continue to make directly assigned adjustments for the Distribution Bypass Deferral Rate Memorandum Account (DBDRMA) in its AET filings. These adjustments will be accomplished as proposed in Advice Letter 3524-E, dated September 15, 2009, and adopted by the Commission in Resolution 4517-E dated December 19, 2013.

l. The costs of the Family Electric Rate Assistance (FERA) program will continue to be assigned as approved by the CPUC in the prior GRC Phase II proceeding.

m. Should the Commission approve an entirely new revenue requirement category to be included in rates between the effective dates of the 2014 GRC Phase II and the 2017

7/ In rare instances, customer charges on select schedules may need to be revised to reflect future changes to schedule-level distribution revenue. Should this occur, revised customer charges will never exceed the levels set here until otherwise revised by the Commission.

GRC Phase II decisions, the Settling Parties agree that the revenue allocation and rate design for that new revenue requirement category should be decided by the Commission at that time and that the rules governing existing revenue requirement categories presented in this settlement will not govern or be precedential for that purpose. Parties will be free to advocate whatever position the party deems appropriate for the new revenue requirement cost category at the time it is under consideration by the Commission.

n. CPUC Fee revenue requirement will be allocated on an equal cents per kWh basis and collected in distribution rates.

IX. WORKSHOPS AND STUDIES FOR THE 2017 GRC PHASE II

1. Agricultural Class Balancing Account Study

A balancing account or other mechanism that addresses the high level of sales variability and sales forecast uncertainty pertaining to the agricultural class, principally as a result of the unpredictability of the availability of surface water, will not be established as part of this Settlement. Instead, parties agree to pursue additional analyses to examine the desirability of such a balancing account, and the necessary components to develop it. Such analyses would review the year-to-year volatility of agricultural class revenues and sales versus other customer class revenues and sales, and include an assessment of possible over-collections of agricultural class revenue that accounts for variation in both PG&E's cost of service and revenues collected due to agricultural sales variability.

PG&E will compile an initial set of data based on input the parties provide to PG&E during the first quarter of 2015, and will provide that data to interested parties, to the extent feasible, for review at least two weeks prior to a workshop at which the data will be discussed. At the workshop, which is to be held no later than 9 months prior to the next GRC Phase II application deadline (and which may be held earlier), the parties will review the available data, provide input with regard to the required analysis, and establish a schedule for completion of the analysis and a workshop report. The schedule will set a date by which PG&E will complete and provide to all parties a report memorializing the analysis, which is targeted to be provided to interested parties no later than 6 months prior to the filing of PG&E's next GRC Phase II application (and which may be provided earlier). The schedule will also include a second workshop at least two weeks following distribution of the report, at which parties will have the opportunity to ask questions about the report and discuss PG&E's analysis and conclusions. The schedule will afford parties an opportunity to provide their own evaluation of the analysis, to be transmitted to PG&E within 6 weeks of service of the initial report, such that evaluations by the parties can be included with the report. The parties envision the completion of the whole agricultural balancing account analysis process by no later than 4 months in advance of the deadline for PG&E's 2017 GRC Phase II application. The report will be included as a compliance item attached to PG&E's next GRC Phase II application.

2. Marginal Cost Workshops

The Settling Parties agree that PG&E will hold up to three workshops to address methodological issues pertaining to the development of marginal costs, including the issues that were raised by the Agricultural Parties and SBUA in this proceeding. Each such workshop would last not more than one day, and each would be noticed on all parties to the 2014 GRC Phase II and be open to all interested participants. Workshop discussions will include: consideration of customer and load growth forecasts; data issues; load diversity; customer access costs for small commercial customers (including variations in customer connection costs within the class); possible alternatives to distribution and customer access marginal cost; and additional topics pertaining to marginal cost calculations and methods for agricultural and other customers.

PG&E will schedule an initial planning conference call to be held within 4 months of the Commission's final decision in this proceeding. PG&E will notice this call on all parties at least 3 weeks prior to the date of the call. In the notice, parties will be asked to provide to PG&E a list of issues to be addressed as part of the workshop process at least one week prior to the call. PG&E will compile this list of potential workshop topics and will circulate the list to all parties to the 2014 GRC Phase II and any other party that has expressed interest. During the initial planning conference call, parties will refine the list of issues to be addressed as part of the final report and will establish a schedule for the workshops, including agenda items for each of the workshops, and a schedule for completion of a post-workshop report.

Pursuant to that schedule, PG&E will conduct up to three workshops and will complete a draft report that summarizes the results of the workshops. PG&E will provide the draft report to the workshop parties and to any other parties to this GRC Phase II who request to receive it. PG&E's draft report will, to the extent possible, identify potential changes to PG&E's prior marginal cost methodologies that it may consider proposing in PG&E's next GRC Phase II proceeding. All parties to this proceeding will be afforded an opportunity to provide their own summary of the workshop process, which may include comments on omissions or differences of opinion, and which will be included with the report if timely received in accordance with the established schedule. The report will be included as a compliance item attached to PG&E's next GRC Phase II application.

X. SETTLEMENT EXECUTION

This Settlement Agreement may be executed in separate counterparts by different Settling Parties hereto and all so executed will be binding and have the same effect as if all the Settling Parties had signed one and the same document. Each such counterparts will be deemed to be an original, but all of which together shall constitute one and the same instrument, notwithstanding that the signatures of all the Settling Parties do not appear on the same page of this Settlement Agreement. This Settlement Agreement shall become effective among the Settling Parties on the date the last Settling Party executes the Settlement Agreement, as indicated below. In witness whereof and intending to be legally bound by the Terms and Conditions of this Settlement Agreement as stated above, the Settling Parties duly execute this Settlement Agreement on behalf of the Settling Parties they represent, as follows:

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Agricultural Energy Consumers' Association

By: /s/

Title: ____________________________

Date: ____________________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

California City-County Streetlight Association

By: /s/

Title: ______________________________

Date: ______________________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

California Farm Bureau Federation

By: /s/

Title: ____________________

Date: ____________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

California Large Energy Consumers' Association

By: /s/

Title: ______________________

Date: ______________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

California League of Food Processors

By: /s/

Title: ______________________

Date: ______________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

California Manufacturing and Technology Association

By: /s/

Title: ______________________________

Date: ______________________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Direct Access Customer Coalition

By: /s/

Title: ______________________________

Date: ______________________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Energy Producers and Users Coalition

By: /s/

Title: ______________________

Date: ______________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Energy Users' Forum

By: /s/

Title: ______________________________

Date: ______________________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Federal Executive Agencies

By: /s/

Title: ____________________

Date: ____________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Office of Ratepayer Advocates

By: /s/

Title: ____________________

Date: ____________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Pacific Gas and Electric Company

By: /s/

Title: ______________________________

Date: ______________________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Small Business Utility Advocates

By: ______/s/______________________

Title: ____________________________

Date: ____________________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

The Utility Reform Network

By: /s/

Title: ______________________________

Date: ______________________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Western Manufactured Housing Communities Association

By: __________/s/______________________

Title: ________________________________

Date: ________________________________

Appendix A

Pacific Gas and Electric Company
2014 General Rate Case Phase II, A.13-04-012

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION
Appendix A

Marginal Generation Energy Costs:

Table 1 - 2014 Marginal Generation Energy Costs by
Time of Use (TOU) Rate Period and Voltage Level (¢/kWh)

Line No.	TOU Rate Period	Voltage Level		
		Transmission	Primary Distribution	Secondary Distribution
1	Summer Peak	5.613	5.718	6.001
2	Summer Partial-Peak	4.791	4.881	5.123
3	Summer Off-Peak	3.654	3.722	3.907
4	Winter Partial-Peak	4.856	4.948	5.192
5	Winter Off-Peak	3.968	4.043	4.243
6	Annual Average	4.266	N.A.	N.A.

Marginal Transmission and Distribution Costs:

Table 2: 2014 Marginal Transmission Capacity Cost ($/kW-Yr)

Line No.	Transmission Capacity
1	34.86

Table 3: 2014 Distribution Marginal Customer Access Costs ($/Customer-Yr)

Line No.	Class	Marginal Customer Access Cost
1	Residential	73.72
2	Agricultural A	321.96
3	Agricultural B	1,457.43
4	Small L & P	323.37
5	A10 Medium L & P Secondary	638.43
6	A10 Medium L & P Primary	1,917.29
7	E19 Secondary	748.05
8	E19 Primary	6,288.92
9	E19 Transmission	6,650.02
10	E20 Secondary	5,559.77
11	E20 Primary	6,688.18
12	E20 Transmission	6,659.54
13	Streetlights	83.05
14	Traffic Control	105.91

Table 4: 2014 Marginal Distribution Capacity Costs by Operating Division

Line No.	Division	Primary Capacity ($/PCAF kW-Yr)	New Business on Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
1	Central Coast	95.45	12.31	4.00
2	De Anza	112.71	22.30	2.45
3	Diablo	52.57	20.78	4.01
4	East Bay	60.29	18.87	1.44
5	Fresno	30.31	8.05	1.61
6	Kern	31.43	7.95	1.97
7	Los Padres	40.87	9.75	2.03
8	Mission	19.87	9.90	1.81
9	North Bay	17.74	12.66	2.13
10	North Coast	42.22	12.65	3.13
11	North Valley	36.06	16.22	3.60
12	Peninsula	38.62	10.46	2.98
13	Sacramento	37.65	13.07	2.21
14	San Francisco	18.33	6.24	1.28
15	San Jose	38.50	12.18	2.79
16	Sierra	29.68	10.15	3.21
17	Stockton	38.26	8.85	2.30
18	Yosemite	45.78	17.54	2.94
19	System	37.33	11.26	2.33

Table 5: 2014 Marginal Distribution Capacity Costs by Distribution Planning Area

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
1	Central Coast	Carmel Valley 12kV	0.00	31.07	31.07	12.31	4.00
2	Central Coast	Gonzales	0.00	31.07	31.07	12.31	4.00
3	Central Coast	Hollister	16.07	31.07	47.14	12.31	4.00
4	Central Coast	King City	129.50	31.07	160.57	12.31	4.00
5	Central Coast	Monterey 21kV	0.00	31.07	31.07	12.31	4.00
6	Central Coast	Mty_4kV (Monterey Bk#1F	0.00	31.07	31.07	12.31	4.00
7	Central Coast	Oilfields	0.00	31.07	31.07	12.31	4.00
8	Central Coast	Prunedale	0.00	31.07	31.07	12.31	4.00
9	Central Coast	Pt Moretti	0.00	31.07	31.07	12.31	4.00
10	Central Coast	Salinas (4/12 kV)	33.73	31.07	64.80	12.31	4.00
11	Central Coast	Santa Cruz Area	0.00	31.07	31.07	12.31	4.00
12	Central Coast	Seaside 4kV	0.00	31.07	31.07	12.31	4.00
13	Central Coast	Seaside-Marina 12kV	60.75	31.07	91.82	12.31	4.00
14	Central Coast	Soledad	0.00	31.07	31.07	12.31	4.00
15	Central Coast	Watsonvlle (12/21kV)	277.75	31.07	308.82	12.31	4.00
16	Central Coast	Watsonvlle (4kV)	0.00	31.07	31.07	12.31	4.00
17	De Anza	Cupertino	0.00	15.15	15.15	22.30	2.45
18	De Anza	Los Altos (12 kV)	130.97	15.15	146.12	22.30	2.45
19	De Anza	Los Altos (4kV)	0.00	15.15	15.15	22.30	2.45
20	De Anza	Los Gatos	101.47	15.15	116.62	22.30	2.45
21	De Anza	Mountain View	70.62	15.15	85.77	22.30	2.45
22	De Anza	Sunnyvale	108.09	15.15	123.24	22.30	2.45
23	Diablo	Alhambra	0.00	28.54	28.54	20.78	4.01
24	Diablo	Brentwood	0.00	28.54	28.54	20.78	4.01
25	Diablo	Clayton / Willow Pass	0.00	28.54	28.54	20.78	4.01
26	Diablo	Concord	22.24	28.54	50.77	20.78	4.01
27	Diablo	Delta (Split Into Bw And Pitts)	0.00	28.54	28.54	20.78	4.01
28	Diablo	Pittsburg	18.00	28.54	46.54	20.78	4.01
29	Diablo	Walnut Creek 12 kV	24.79	28.54	53.32	20.78	4.01
30	Diablo	Walnut Creek 21 kV	30.60	28.54	59.14	20.78	4.01
31	East Bay	C-D-L	128.09	8.29	136.39	18.87	1.44
32	East Bay	Edes-J	0.00	8.29	8.29	18.87	1.44
33	East Bay	K-X	0.00	8.29	8.29	18.87	1.44
34	East Bay	North	0.00	8.29	8.29	18.87	1.44
35	East Bay	South	60.14	8.29	68.44	18.87	1.44

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
36	Fresno	Auberry	0.00	12.54	12.54	8.05	1.61
37	Fresno	Central Fresno	18.64	12.54	31.18	8.05	1.61
38	Fresno	Clovis	0.00	12.54	12.54	8.05	1.61
39	Fresno	Coalinga	0.00	12.54	12.54	8.05	1.61
40	Fresno	Corcoran	24.03	12.54	36.57	8.05	1.61
41	Fresno	Dunlap	0.00	12.54	12.54	8.05	1.61
42	Fresno	Figarden	0.00	12.54	12.54	8.05	1.61
43	Fresno	Gates	21.18	12.54	33.72	8.05	1.61
44	Fresno	Henrietta	0.00	12.54	12.54	8.05	1.61
45	Fresno	Kerman	39.56	12.54	52.09	8.05	1.61
46	Fresno	Kettleman	14.83	12.54	27.36	8.05	1.61
47	Fresno	Kingsburg	27.89	12.54	40.42	8.05	1.61
48	Fresno	Lemoore	0.00	12.54	12.54	8.05	1.61
49	Fresno	Mcmullin	0.00	12.54	12.54	8.05	1.61
50	Fresno	Reedley	38.38	12.54	50.92	8.05	1.61
51	Fresno	Sanger	0.00	12.54	12.54	8.05	1.61
52	Fresno	South Fresno	0.00	12.54	12.54	8.05	1.61
53	Fresno	Stone Corral	0.00	12.54	12.54	8.05	1.61
54	Fresno	Woodchuck	0.00	12.54	12.54	8.05	1.61
55	Fresno	Woodward	38.63	12.54	51.17	8.05	1.61
56	Kern	Arvin	41.52	18.60	60.12	7.95	1.97
57	Kern	Blackwell	0.00	18.60	18.60	7.95	1.97
58	Kern	Carrizo Plains	0.00	18.60	18.60	7.95	1.97
59	Kern	Cuyama	0.00	18.60	18.60	7.95	1.97
60	Kern	Lamont	0.00	18.60	18.60	7.95	1.97
61	Kern	Lerdo	0.00	18.60	18.60	7.95	1.97
62	Kern	Mc Kittrick	0.00	18.60	18.60	7.95	1.97
63	Kern	Poso Mountain	0.00	18.60	18.60	7.95	1.97
64	Kern	Taft	0.00	18.60	18.60	7.95	1.97
65	Kern	Urban Bakersfield (East)	0.00	18.60	18.60	7.95	1.97
66	Kern	Urban Bakersfield (Ne)	0.00	18.60	18.60	7.95	1.97
67	Kern	Urban Bakersfield (Nw)	0.00	18.60	18.60	7.95	1.97
68	Kern	Urban Bakersfield (Sw)	36.99	18.60	55.59	7.95	1.97
69	Kern	Wasco	0.00	18.60	18.60	7.95	1.97
70	Los Padres	Cholame	0.00	19.08	19.08	9.75	2.03
71	Los Padres	Lompoc	0.00	19.08	19.08	9.75	2.03

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
72	Los Padres	North Coast	0.00	19.08	19.08	9.75	2.03
73	Los Padres	Oceano	0.00	19.08	19.08	9.75	2.03
74	Los Padres	Paso Robles	27.17	19.08	46.25	9.75	2.03
75	Los Padres	San Luis Obispo	51.72	19.08	70.80	9.75	2.03
76	Los Padres	Santa Maria	0.00	19.08	19.08	9.75	2.03
77	Los Padres	Santa Ynez	0.00	19.08	19.08	9.75	2.03
78	Los Padres	Sisquoc	0.00	19.08	19.08	9.75	2.03
79	Mission	Fremont 12 kV	31.81	10.46	42.27	9.90	1.81
80	Mission	Fremont 21 kV	0.00	10.46	10.46	9.90	1.81
81	Mission	Hayward 12 kV	0.00	10.46	10.46	9.90	1.81
82	Mission	Livermore 21kV	0.00	10.46	10.46	9.90	1.81
83	Mission	San Ramon - Vineyard	0.00	10.46	10.46	9.90	1.81
84	Mission	Tri-Valley/Livermore 12kV	0.00	10.46	10.46	9.90	1.81
85	North Bay	Bahia (Or Benicia)	0.00	9.90	9.90	12.66	2.13
86	North Bay	Marin (Central)	0.00	9.90	9.90	12.66	2.13
87	North Bay	Marin (Coastal)	0.00	9.90	9.90	12.66	2.13
88	North Bay	Marin (Northern)	0.00	9.90	9.90	12.66	2.13
89	North Bay	Marin (Southern)	0.00	9.90	9.90	12.66	2.13
90	North Bay	Monticello	0.00	9.90	9.90	12.66	2.13
91	North Bay	Napa	0.00	9.90	9.90	12.66	2.13
92	North Bay	Silverado	0.00	9.90	9.90	12.66	2.13
93	North Bay	Vallejo	0.00	9.90	9.90	12.66	2.13
94	North Bay	Vallejo 24kV	0.00	9.90	9.90	12.66	2.13
95	North Bay	Vallejo 4kV	0.00	9.90	9.90	12.66	2.13
96	North Coast	Arcata	0.00	16.39	16.39	12.65	3.13
97	North Coast	Bellevue / Cotati	14.50	16.39	30.89	12.65	3.13
98	North Coast	Bridgeville	0.00	16.39	16.39	12.65	3.13
99	North Coast	Clearlake (East)	0.00	16.39	16.39	12.65	3.13
100	North Coast	Clearlake (West)	62.81	16.39	79.20	12.65	3.13
101	North Coast	Cloverdale / Geyserville	0.00	16.39	16.39	12.65	3.13
102	North Coast	Eureka	122.25	16.39	138.63	12.65	3.13
103	North Coast	Fairhaven	0.00	16.39	16.39	12.65	3.13
104	North Coast	Fitch Mountain/Fulton	0.00	16.39	16.39	12.65	3.13
105	North Coast	Garberville	0.00	16.39	16.39	12.65	3.13
106	North Coast	Hopland	0.00	16.39	16.39	12.65	3.13
107	North Coast	Maple Creek	0.00	16.39	16.39	12.65	3.13

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
108	North Coast	Mendo Coast (North)	0.00	16.39	16.39	12.65	3.13
109	North Coast	Mendo Coast (South)	0.00	16.39	16.39	12.65	3.13
110	North Coast	Middletown	0.00	16.39	16.39	12.65	3.13
111	North Coast	Newburg/Rio Dell (Fortuna)	0.00	16.39	16.39	12.65	3.13
112	North Coast	Orick/ Big Lagoon	0.00	16.39	16.39	12.65	3.13
113	North Coast	Petaluma	0.00	16.39	16.39	12.65	3.13
114	North Coast	Petaluma 4 kV	0.00	16.39	16.39	12.65	3.13
115	North Coast	Philo	0.00	16.39	16.39	12.65	3.13
116	North Coast	Potter Valley	0.00	16.39	16.39	12.65	3.13
117	North Coast	Santa Rosa	13.35	16.39	29.74	12.65	3.13
118	North Coast	Sebastopol	0.00	16.39	16.39	12.65	3.13
119	North Coast	Sonoma	0.00	16.39	16.39	12.65	3.13
120	North Coast	Sonoma Coast	0.00	16.39	16.39	12.65	3.13
121	North Coast	Ukiah Valley	470.94	16.39	487.33	12.65	3.13
122	North Coast	Willits	247.44	16.39	263.83	12.65	3.13
123	North Coast	Willowcreek	0.00	16.39	16.39	12.65	3.13
124	North Valley	Antler 12 kV	0.00	24.26	24.26	16.22	3.60
125	North Valley	Bucks	0.00	24.26	24.26	16.22	3.60
126	North Valley	Burney 12 kV	0.00	24.26	24.26	16.22	3.60
127	North Valley	Cedar Creek	0.00	24.26	24.26	16.22	3.60
128	North Valley	Chester	0.00	24.26	24.26	16.22	3.60
129	North Valley	Chico 12 kV	0.00	24.26	24.26	16.22	3.60
130	North Valley	Clark	0.00	24.26	24.26	16.22	3.60
131	North Valley	Corning 12 kV	0.00	24.26	24.26	16.22	3.60
132	North Valley	Corning 4 kV	0.00	24.26	24.26	16.22	3.60
133	North Valley	Elk Creek	0.00	24.26	24.26	16.22	3.60
134	North Valley	French Gulch	0.00	24.26	24.26	16.22	3.60
135	North Valley	Gridley	38.23	24.26	62.49	16.22	3.60
136	North Valley	Indian Valley (Removed)	0.00	24.26	24.26	16.22	3.60
137	North Valley	Lake Almanor	0.00	24.26	24.26	16.22	3.60
138	North Valley	Mcarthur	0.00	24.26	24.26	16.22	3.60
139	North Valley	Orland	0.00	24.26	24.26	16.22	3.60
140	North Valley	Oroville 12 kV	0.00	24.26	24.26	16.22	3.60
141	North Valley	Oroville 4 kV	0.00	24.26	24.26	16.22	3.60
142	North Valley	Paradise	0.00	24.26	24.26	16.22	3.60
143	North Valley	Pit #3	0.00	24.26	24.26	16.22	3.60
144	North Valley	Pit #5	0.00	24.26	24.26	16.22	3.60

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
145	North Valley	Quincy	0.00	24.26	24.26	16.22	3.60
146	North Valley	Red Bluff	565.14	24.26	589.41	16.22	3.60
147	North Valley	Redding 12 kV	0.00	24.26	24.26	16.22	3.60
148	North Valley	Rising River 12 kV	0.00	24.26	24.26	16.22	3.60
149	North Valley	Volta	0.00	24.26	24.26	16.22	3.60
150	North Valley	Whitmore	0.00	24.26	24.26	16.22	3.60
151	North Valley	Wildwood	0.00	24.26	24.26	16.22	3.60
152	North Valley	Willows	0.00	24.26	24.26	16.22	3.60
153	Peninsula	Central Peninsula 12 kV	0.00	13.04	13.04	10.46	2.98
154	Peninsula	Central Peninsula 21 kV	0.00	13.04	13.04	10.46	2.98
155	Peninsula	Central Peninsula 4 kV	0.00	13.04	13.04	10.46	2.98
156	Peninsula	Ne Peninsula 4 kV	0.00	13.04	13.04	10.46	2.98
157	Peninsula	North Pen East 12 kV	0.00	13.04	13.04	10.46	2.98
158	Peninsula	North Pen West 12 kV	0.00	13.04	13.04	10.46	2.98
159	Peninsula	South Peninsula 4 kV	67.50	13.04	80.54	10.46	2.98
160	Peninsula	South-East Peninsula 12 kV	0.00	13.04	13.04	10.46	2.98
161	Peninsula	South-West Peninsula 12 kV	224.91	13.04	237.95	10.46	2.98
162	Peninsula	West Peninsula 12 kV	27.06	13.04	40.10	10.46	2.98
163	Sacramento	Davis	32.14	18.94	51.08	13.07	2.21
164	Sacramento	Grand Island	0.00	18.94	18.94	13.07	2.21
165	Sacramento	North Colusa	0.00	18.94	18.94	13.07	2.21
166	Sacramento	Peabody	0.00	18.94	18.94	13.07	2.21
167	Sacramento	South Colusa	0.00	18.94	18.94	13.07	2.21
168	Sacramento	Suisun / Cordelia	0.00	18.94	18.94	13.07	2.21
169	Sacramento	Vacaville	41.05	18.94	59.98	13.07	2.21
170	Sacramento	West Sacramento	0.00	18.94	18.94	13.07	2.21
171	Sacramento	Woodland	18.90	18.94	37.84	13.07	2.21
172	Sacramento	Yolo / Colusa River Ag	0.00	18.94	18.94	13.07	2.21
173	Sacramento	Yolo Ag (North)	0.00	18.94	18.94	13.07	2.21
174	Sacramento	Yolo Ag (West)	0.00	18.94	18.94	13.07	2.21
175	San Francisco	Embarcadero (12kV)	0.00	8.17	8.17	6.24	1.28
176	San Francisco	Embarcadero (35kV)	0.00	8.17	8.17	6.24	1.28
177	San Francisco	Potrero	7.23	8.17	15.40	6.24	1.28

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
178	San Francisco	S Of Army (A Hunterspt)	0.00	8.17	8.17	6.24	1.28
179	San Francisco	S Of Army (H Martin 12kV)	0.00	8.17	8.17	6.24	1.28
180	San Francisco	X (Mission)	0.00	8.17	8.17	6.24	1.28
181	San Francisco	Y (Larkin)	92.66	8.17	100.83	6.24	1.28
182	San Jose	Evergreen	0.00	11.20	11.20	12.18	2.79
183	San Jose	Gilroy	148.91	11.20	160.11	12.18	2.79
184	San Jose	Milpitas	0.00	11.20	11.20	12.18	2.79
185	San Jose	Morgan Hill	0.00	11.20	11.20	12.18	2.79
186	San Jose	San Jose (West)	45.36	11.20	56.56	12.18	2.79
187	San Jose	San Jose (Downtown 12kV)	0.00	11.20	11.20	12.18	2.79
188	San Jose	San Jose (Downtown 4kV)	0.00	11.20	11.20	12.18	2.79
189	San Jose	San Jose (East)	49.63	11.20	60.83	12.18	2.79
190	San Jose	San Jose (North)	55.30	11.20	66.50	12.18	2.79
191	San Jose	San Jose (South) 12kV	0.00	11.20	11.20	12.18	2.79
192	San Jose	San Jose (South) 21kV	32.94	11.20	44.14	12.18	2.79
193	Sierra	Alleghany	0.00	14.64	14.64	10.15	3.21
194	Sierra	Apple To Echo	0.00	14.64	14.64	10.15	3.21
195	Sierra	Bear River	68.96	14.64	83.60	10.15	3.21
196	Sierra	Bonnie Nook/Shady Glen	0.00	14.64	14.64	10.15	3.21
197	Sierra	Central Nevada	0.00	14.64	14.64	10.15	3.21
198	Sierra	Clarksville / Shingle Springs	25.39	14.64	40.03	10.15	3.21
199	Sierra	Columbia Hill	0.00	14.64	14.64	10.15	3.21
200	Sierra	Diamond Spr / Placerville	0.00	14.64	14.64	10.15	3.21
201	Sierra	Donner Summit	0.00	14.64	14.64	10.15	3.21
202	Sierra	Forest Hill	0.00	14.64	14.64	10.15	3.21
203	Sierra	Horseshoe	0.00	14.64	14.64	10.15	3.21
204	Sierra	Lincoln	0.00	14.64	14.64	10.15	3.21
205	Sierra	Marysville	0.00	14.64	14.64	10.15	3.21
206	Sierra	Mtn Quarries	0.00	14.64	14.64	10.15	3.21
207	Sierra	Narrows	0.00	14.64	14.64	10.15	3.21
208	Sierra	New Yuba Foothills	0.00	14.64	14.64	10.15	3.21
209	Sierra	North Placer	0.00	14.64	14.64	10.15	3.21
210	Sierra	Pike	0.00	14.64	14.64	10.15	3.21

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
211	Sierra	South Placer	5.80	14.64	20.43	10.15	3.21
212	Sierra	Yuba City	23.90	14.64	38.54	10.15	3.21
213	Stockton	Angles Camp	0.00	15.88	15.88	8.85	2.30
214	Stockton	Clay	0.00	15.88	15.88	8.85	2.30
215	Stockton	Corral	0.00	15.88	15.88	8.85	2.30
216	Stockton	Jackson	118.22	15.88	134.10	8.85	2.30
217	Stockton	Linden 12 kV	147.97	15.88	163.85	8.85	2.30
218	Stockton	Lodi 12 & 21 kV	0.00	15.88	15.88	8.85	2.30
219	Stockton	Lodi 4 kV	0.00	15.88	15.88	8.85	2.30
220	Stockton	Manteca 17 kV	15.76	15.88	31.64	8.85	2.30
221	Stockton	Manteca 4 kV	0.00	15.88	15.88	8.85	2.30
222	Stockton	Middle River	0.00	15.88	15.88	8.85	2.30
223	Stockton	North Stockton 12 kV	0.00	15.88	15.88	8.85	2.30
224	Stockton	North Stockton 21 kV	0.00	15.88	15.88	8.85	2.30
225	Stockton	North Stockton 4 kV	0.00	15.88	15.88	8.85	2.30
226	Stockton	Salt Springs	0.00	15.88	15.88	8.85	2.30
227	Stockton	South Stockton 12 kV	18.70	15.88	34.58	8.85	2.30
228	Stockton	South Stockton 4 kV	0.00	15.88	15.88	8.85	2.30
229	Stockton	Tracy 12 kV	37.19	15.88	53.07	8.85	2.30
230	Yosemite	Atwater	0.00	25.10	25.10	17.54	2.94
231	Yosemite	Canal	40.88	25.10	65.98	17.54	2.94
232	Yosemite	Chowchilla	60.11	25.10	85.21	17.54	2.94
233	Yosemite	Indian Flat	0.00	25.10	25.10	17.54	2.94
234	Yosemite	Mariposa	0.00	25.10	25.10	17.54	2.94
235	Yosemite	Mendota	51.05	25.10	76.16	17.54	2.94
236	Yosemite	Merced 12kV	0.00	25.10	25.10	17.54	2.94
237	Yosemite	Merced 21kV	0.00	25.10	25.10	17.54	2.94
238	Yosemite	Merced Falls	0.00	25.10	25.10	17.54	2.94
239	Yosemite	Newhall	0.00	25.10	25.10	17.54	2.94
240	Yosemite	Newman (1)	0.00	25.10	25.10	17.54	2.94
241	Yosemite	Oakdale	0.00	25.10	25.10	17.54	2.94
242	Yosemite	Oakhurst	0.00	25.10	25.10	17.54	2.94
243	Yosemite	Oro Loma	0.00	25.10	25.10	17.54	2.94
244	Yosemite	Rio Mesa (2)	0.00	25.10	25.10	17.54	2.94
245	Yosemite	Sonora	0.00	25.10	25.10	17.54	2.94
246	Yosemite	Spring Gap	0.00	25.10	25.10	17.54	2.94

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247	Yosemite	Storey	0.00	25.10	25.10	17.54	2.94
248	Yosemite	Westley (1)	0.00	25.10	25.10	17.54	2.94

Yosemite Division Notes:
(1) The new Westley DPA load is excluded from the Newman DPA.
(2) Newly created DPA in 2009. Split from the Storey DPA. Prior to 2009 peak load part of Storey DPA.