STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

November 15, 2011 Agenda ID #10850
Ratesetting

TO PARTIES OF RECORD APPLICATION 10-03-014.

This is the proposed decision of Administrative Law Judge (ALJ) Thomas R. Pulsifer. It will not appear on the Commission's agenda sooner than 30 days from the date it is mailed. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 25 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ Thomas R. Pulsifer at trp@cpuc.ca.gov and the assigned Commissioner. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ JANET A. ECONOME for
Karen V. Clopton, Chief
Administrative Law Judge

KVC:lil

Attachment

Decision **PROPOSED DECISION OF ALJ PULSIFER** (Mailed 11/15/2011)

**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, including Real Time Pricing, to Revise its Customer Energy Statements, and to Seek Recovery of Incremental Expenditures. (U39M.) | Application 10-03-014<br>(Filed March 22, 2010) |

# DECISION ADOPTING ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION AND NON-RESIDENTIAL RATE DESIGN FOR PACIFIC GAS AND ELECTRIC COMPANY

# TABLE OF CONTENTS

**Title** **Page**

**TABLE OF CONTENTS**
**(Cont'd)**

**Title** **Page**

**TABLE OF CONTENTS**
**(Cont'd)**

**Title** **Page**

## DECISION ADOPTING ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION AND NON-RESIDENTIAL RATE DESIGN FOR PACIFIC GAS AND ELECTRIC COMPANY

### 1. Summary

Pursuant to Pacific Gas and Electric Company's (PG&E) general rate case (GRC) Phase 2 application, we adopt the design of electric retail rates based on adopted marginal costs and revenue allocation to the customer class level.[1] The resulting rates will allow PG&E to collect the revenue requirement previously determined in its Phase 1 test year GRC, as modified by subsequent revenue requirement decisions. Revised rates will become effective January 1, 2012.

PG&E and interested parties submitted a range of evidence and entered into a series of settlement agreements regarding marginal cost and revenue allocation, and non-residential rate design issues. PG&E proposes to adjust its current rates and tariff schedules for customers pursuant to the terms of the Settlement Agreements. Based on our review of the proposals in light of the whole record, we approve all of the settlements submitted in Phase 2, and attached as appendices to this decision.

The following table summarizes the adopted percentage increase or decrease in average electric rates for each major customer class as a result of the revenue allocation settlement agreement approved herein. While the allocation of revenue among customer classes changes, the overall effect on total utility revenues is zero, as summarized below:

---

[1] The majority of rate design issues for PG&E residential electric customers in this proceeding were previously resolved in D.11-05-047.

| Revenue Allocation Class | Percentage Increase (or Decrease) |
|---|---|
| • Residential | 0.6% |
| • Small Light & Power | 0.2% |
| • Medium Light & Power: | -0.9% |
| • E-19 Class: | -0.9% |
| • Streetlights | 1.5% |
| • Standby | 1.7% |
| • Agricultural | 1.5% |
| • E-20 : | -1.0% |
| Total | 0.0 |

## 2. Procedural Background

This decision resolves issues in Pacific Gas and Electric Company's (PG&E) Phase II general rate case (GRC) application relating to marginal costs, revenue allocation and remaining rate design issues that were not resolved by the previous decision in this application which resolved the majority of residential rate design issues. This decision concludes the resolution of remaining Phase 2 issues.

PG&E filed its application on March 22, 2010, and served initial testimony on its marginal cost, revenue allocation, and rate design proposals. The application was protested on April 26, 2010, by the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), Disability Rights Advocates (DisabRA), Vote Solar, Solar Alliance, and South San Joaquin Irrigation District (SSJID). On May 19, 2010, a prehearing conference was held before Administrative Law Judge (ALJ) Pulsifer. Assigned Commissioner Peevey issued his Ruling and Scoping Memo dated May 26, 2010 (Scoping Memo) setting the scope of the proceeding and procedural schedule.

On June 30, 2010, PG&E filed a scheduled update of its March 22, 2010 application to revise illustrative rates to reflect the 2011 forecast of sales and rates in effect on June 1, 2010, and to make marginal cost revisions. The June 30, 2010 update figures served as the basis for all other parties' subsequent responsive testimony. Pursuant to ruling dated December 8, 2010, PG&E on January 7, 2011 again updated its showing on marginal costs, revenue allocation and non-residential rate design. By ruling dated January 19, 2011, parties' rebuttal testimony was submitted on March 4, 2011, with sur-rebuttal testimony due on March 25, 2011.

The Commission's DRA served testimony on September 8, 2010. On October 6, 2010, various intervenors served testimony. Hearings for marginal costs, revenue allocation and non-residential rate design were deferred to provide for settlement discussions. PG&E subsequently entered into a series of settlements covering all remaining Phase 2 issues, and filed motions for approval of the settlements, as summarized below.

| Date of Motion | Scope of Settlement Agreement |
|---|---|
| a. March 14, 2011 | Marginal Cost and Revenue Allocation |
| b. April 8, 2011 | Medium and Large Light and Power (MLLP) Rate Design |
| c. April 8, 2011 (As amended September 22, 2011) | Small Light and Power (SLP) Rate Design |
| d. June 3, 2011 | Streetlighting Rate Design Settlement Agreement |
| e. June 22, 2011 | Schedule ES and Natural Gas Baseline Quantities |
| f. July 18, 2011 | Agricultural Rate Design |

Each of the settlements is supported by all active parties participating in each respective settlement with the exception of limited opposition to certain elements, noted below.

On May 9, 2011, comments in opposition to the MLLP Settlement were filed by The Solar Alliance, The Vote Solar Initiative, and Sierra Club California. PG&E filed a reply on May 24, 2011. Pursuant to ruling issued on June 8, 2011, evidentiary hearings were held on the disputed MLLP settlement issues on August 29 and 30, 2011. Opening briefs were filed on September 19, 2011, and reply briefs were filed on October 3, 2011.

On October 6, 2010, Lamont Public Utilities District (Lamont) submitted testimony proposing an expansion of Agricultural Rate Schedule E-37. On August 1, 2011, Lamont filed comments opposing the Agricultural Settlement. PG&E filed a response to Lamont on August 8, 2011. PG&E and Lamont subsequently submitted additional testimony relating to this dispute. Based on a stipulation for the admission of relevant exhibits, PG&E and Lamont mutually waived cross examination. Thus, no evidentiary hearings were held. Opening briefs were filed on October 10, 2011, and reply briefs were filed on October 18, 2011. Although no other parties sponsored testimony responding to Lamont's proposal, reply briefs in opposition to Lamont were filed by PG&E, TURN, California Large Energy Consumers Association (CLECA), and Energy Producers and Users Coalition (EPUC).

Western Manufactured Housing Communities Association (WMA) sponsored testimony in opposition to PG&E's proposed treatment of the Rate Schedule ET Discount for Master Meter Mobile Home Park Customers. TURN was the only other party who sponsored testimony on the Mobile Home Park (MHP) disputed issues. Hearings on the disputed MHP issues were held on

August 17 and 18, 2011. Opening briefs were filed on September 23, 2011, and reply briefs were filed on October 7, 2011.

In view of parties' agreement to enter into settlements, the settling parties waived hearings. The ALJ granted hearings only on the specific contested issues as identified above. By ruling dated October 11, 2011, the ALJ granted motions to admit underlying testimony and other supporting exhibits on Phase 2 issues that were not subject to cross examination. The admission of this evidence completes the record and provides an evidentiary basis to evaluate the reasonableness of the settlements, and remaining Phase 2 disputed issues.

## 3. Disposition of Substantive Issues

### 3.1. Marginal Cost and Revenue Allocation Settlement

In this decision, we adopt marginal costs of electric generation, transmission, distribution, and customer access to serve as the basis for allocating generation and distribution revenue among rate groups for use in the design of PG&E's retail electric rates. The adopted marginal costs, revenue allocation and rate design support the key objectives of (1) redesigning electric rates to more closely align with cost-causation principles; and (2) simplifying electric rates and tariffs to make them easier for customers to understand and (3) continuing to move electric rates closer to cost of service, while also taking public purpose considerations into account.

PG&E allocates revenue separately for various components of bundled service rates. Since the revenue allocation rules and policies for most of these components have been established in other proceedings, the proposals in this proceeding are limited to revising or updating methods for setting distribution and generation rate components as well as for Public Purpose Programs (PPP).

PG&E presented illustrative revenue allocation and rate design calculations based on 2011 revenues applied to forecasted 2011 billing determinants.

DRA served testimony on revenue allocation, marginal cost, and non-residential rate design issues on September 8, 2010. Other intervenors served testimony on these issues on October 6, 2010. Agricultural Energy Consumers Association (AECA), California City-County Street Light Association (CAL-SLA); California Farm Bureau (CFBF); CLECA; California Manufacturers & Technology Association (CMTA); Direct Access Customer Coalition (DACC); EPUC; Energy Users Forum (EUF); Federal Executive Agencies (FEA) provided testimony on marginal costs, revenue allocation and rate design that were not the subject of the residential rate design portion of Phase 2.

On March 14, 2011, PG&E filed a motion for adoption of the Marginal Cost and Revenue Allocation Settlement Agreement.[2] The Settlement Agreement, reproduced in Appendix A hereto, resolves all marginal cost and revenue allocation issues except the specific marginal costs to be used solely for the purpose of establishing unit costs where needed for customer specific contract rate floors for customer retention and attraction.

The Settlement Agreement does not adopt any party's marginal cost principles or proposals, but, for purposes of calculating the revenue allocation, uses PG&E's updated marginal costs, as provided in its January 7, 2011 testimony. The Settlement proposes to allocate electric revenue on an overall revenue-neutral basis among classes to preserve PG&E's total authorized revenue.

---

[2] The Settling Parties are: AECA, CAL-SLA; CFBF; CLECA; CMTA; DACC; DRA; EPUC; EUF; FEA; PG&E; SSJID; TURN, and WMA.

The Settling Parties agree that PG&E will target the average percentage change for every customer group at the levels shown in Table 1, but the final, actual results will vary somewhat based on rate changes that may occur before this Settlement Agreement is implemented. For example, the final adopted residential rate design and resulting reallocation of revenue due to the revised CARE surcharge will necessarily cause the final initial percentage changes to vary somewhat from those shown in the Settlement Agreement.

The Settling Parties propose that rates will be changed to reflect changes in revenue requirement in the manner set forth in the Settlement Agreement. Each customer group will be held responsible for approximately the same percentage contribution to each component of rates. This will be accomplished by applying to each rate schedule the same percentage changes to rates by component required to collect the revenue requirement for that component, with specific exceptions to this treatment set forth in the Settlement Agreement. To this end, the Settlement Agreement addresses the treatment of each component of rates and establishes specific treatment for six categories of revenue requirement collected in distribution rates.

#### 3.1.1. Data and Modeling Workshops for 2014 GRC Phase 2

PG&E agrees to hold workshops for parties to its 2011 GRC Phase 2 proceeding prior to filing its 2014 GRC Phase 2 application, to discuss the data and/or methodologies that might be used in that proceeding. These workshops will discuss data, methodologies, and potential model simplification and transparency, as detailed in the Settlement for:

1. The marginal generation cost data that might be used in that proceeding to develop marginal costs;

2. The marginal distribution capacity costs and marginal customer access cost (MCAC) data that might be used in that proceeding to develop marginal costs; and
3. The revenue allocation methodologies that might be used to develop positions in the 2014 GRC Phase 2.

The Settling Parties agree that revenue allocation and rate design for new categories of revenue requirement added to rates before Phase 2 of the 2014 GRC should be decided by the Commission at that time, and that rules governing the existing revenue requirement categories presented in the Settlement Agreement will not govern or be precedential for that purpose.

Based on the standards of review for all-party settlements as discussed further in Section 4 below, we conclude that the marginal cost and revenue allocation settlement agreement is reasonable and hereby adopt it. We direct PG&E to implement the provisions of the settlement as directed below.

### 3.2. Medium and Large Light and Power Rate Design Settlement

Multiple parties[3] entered into a settlement addressing medium and large light & power (MLLP) rate design.[4] The MLLP Settlement is supplemental to the March 14 Revenue Allocation Settlement, and uses the same revenue allocation assumptions. The MLLP Settlement addresses the marginal costs to be used for discounted price floors for use with Schedules ED, E-31 or special contracts, which was referenced but not resolved in the March 14 Settlement.

---

[3] The parties sponsoring the MLLP Settlement are: CLECA; CMTA; DRA; EPUC; Energy Users Forum (EUF); Federal Executive Agencies (FEA); and PG&E.

[4] The MLLP customer classes encompass and are defined as: Schedules A-10, A-10 TOU, E-19V,Mandatory E-19, E-20, and Standby, as described in Exhibit PGE-14 Chapter 5.

The MLLP Settling Parties agree that rates to collect the revenue allocated to the MLLP customer classes under the March 14 Settlement shall be designed consistent with the illustrative rates set forth below and in Exhibit A, for Schedules A-10, A-10 TOU, E-19V, Mandatory E-19, E-20, and Standby.

Exhibit A includes updates to Standby customer charges to reflect the $10 single-phase and $20 polyphase customer charge levels agreed to in the SLP Settlement for Schedules A-1 and A-6. The MLLP Settling Parties agree that the methodologies underlying the illustrative rates shall serve as a starting point for updating and determining rate changes necessary to collect the adopted revenue requirement in effect when the Settlement is implemented.

The MLLP Settlement includes the following fundamental components

#### 3.2.1. Basic rate design Updates

Each applicable MLLP rate schedule is to be updated upon implementation of the MLLP settlement, using the methods underlying the illustrative settlement rates for Schedules A- 10, A-10 TOU, E-19V, mandatory E-19, E-20, and Standby rates as presented in Exhibit B to the Settlement. Standby customer charges are updated to reflect the $10 single-phase and $20 polyphase levels per the Schedule A-1 and A-6 settlement customer charges.

#### 3.2.2. Summer Average Rate Limiters:

The Schedule E-19 and E-20 primary and secondary summer season average rate limiters are eliminated.

#### 3.2.3. Schedule A-6 Solar Pilot/Schedule E-19 and E-20 Option R Rates:

The 90-day opt-in period to participate in the A-6 Solar Pilot for existing Schedule E-19 solar customers is eliminated. The settlement maintains the Schedule A-6 Solar Pilot with a 20 megawatts (MW) cap on participating load. In the event a current participant drops out, new enrollment to fill the 20 MW cap may occur. The settlement does not accept the E-19 and E-20 Option R rates as proposed by Solar Alliance. The opposition to this provision of the settlement raised by Solar Alliance is addressed in Section 3.2.8 below.

#### 3.2.4. Schedule E-BIP:

The standard Interruptible Program (Schedule E-BIP) discounts or incentive levels shall be evaluated in the 2012- 2014 Demand Response proceeding (Application 11-03-001).

#### 3.2.5. Peak Day Pricing (PDP) Refinements:

PDP refinements to Schedules A-10-TOU, E-19, and E-20 are adopted as proposed by PG&E in Chapter 9 of Exhibit (PG&E-14).

#### 3.2.6. Commercial Submetering Report:

The Commercial Submetering report ordered in D.09-07-004 is agreed to be unnecessary, as no commercial master-metered buildings appear to have installed submetering systems to prorate the master-meter bill among tenants. The settling parties agree the requirement to produce the report should be eliminated. We accept this provision and accordingly eliminate this requirement as ordered in D.09-07-004.

#### 3.2.7. Discounted Price Floors:

Discounted price floors for Schedule ED, E-31, or other discounted rates or special contracts will use (a) price floors based upon the average of the generation marginal energy costs adopted in the 2007 GRC Phase 2 in D.07-09-004 and the 2011 generation marginal energy costs presented in PG&E's January 7, 2011 GRC Phase 2 Update testimony, and (b) price floors based upon the updated transmission and distribution (T&D) marginal costs and generation marginal capacity costs presented in PG&E's January 7, 2011 GRC Phase 2 Update testimony.

#### 3.2.8. Solar Parties' Opposition to the MLLP Settlement

As noted above, comments in opposition to the MLLP Settlement were jointly filed on May 9, 2011, by The Solar Alliance, The Vote Solar Initiative, and Sierra Club California. Testimony in opposition to the MLLP Settlement was sponsored by Thomas Beach on behalf of Solar Alliance.

The MLLP settlement rejects Solar Alliance's proposal to increase participation in the Schedule A-6 Solar pilot from 20 MW to 50MW. Under the existing Schedule A-6 Solar Pilot, customers otherwise required to take service under Schedule E-19 (i.e., customers with ordinary demands above 500 kilowatt (kW)) are allowed to take service on Schedule A-6 if they serve at least 20 % of their maximum demand with solar Distributed Generation (DG). The MLLP settling parties believe that expanding the A-6 Solar Pilot is unjustified, and would create additional revenue shortfalls above those already caused by the current A-6 Solar Pilot with the 20 MW cap.

Solar Alliance also proposes a new "Option R" under Schedules E-10 and E-20 which would replace the otherwise-applicable generation capacity-based time-of-use (TOU) demand charges with TOU energy charges, and replace 50 percent of the standard non-TOU distribution-related maximum demand charges with non-TOU energy charges. Solar Alliance proposes that Schedule E-19 and 20 customers who serve at least 10% of their peak demand with qualifying renewable DG be eligible for this new tariff option, up to a cap of 250 MW of newly-installed DG capacity.[5]

Solar Alliance's proposals would provide solar customers with reduced demand charges offset by higher time-differentiated (per kilowatt-hour (kWh)) energy rates. Together, Solar Alliance's proposed changes would eliminate approximately one-half of the revenue currently collected in PG&E's TOU and maximum demand charges under Schedules E-19 and E-20 and convert these demand-related rate elements to volumetric energy charges.

The MLLP Settling Parties also oppose Solar Alliance's proposed Option R rate which would allow solar customers to qualify for lower demand charges. The MLLP Settling Parties further believe that the 90-day opt-in period to participate in the A-6 Solar Pilot for existing Schedule E-19 customers is obsolete and should be eliminated.

Solar Alliance's Option R proposal offers features similar to those previously adopted for the large light & power customers of Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E). Similar to the SDG&E and SCE Option R rates, Solar Alliance proposes to allocate 50% of the distribution costs in non-coincident demand charges to TOU energy charges on an equal cents-per-kWh basis across all time periods. Additionally, Solar Alliance's proposed option R rate would shift all generation-related peak and partial-peak demand charges to TOU energy charges. PG&E

5 See Beach Opening Testimony at 37-38.

would thus recover all generation –related capacity costs through summer peak and partial peak energy charges.[6]

The Commission adopted the Option R rates for SCE and SDG&E a part of settlements and is under no obligation to adopt similar rates or policies for PG&E in this case. Solar Alliance contends, however, that there are no reasons why PG&E's circumstances warrant different treatment from that authorized for SCE and SDG&E.

Solar Alliance argues that Senate Bill (SB) 1 (enacted as Public Utilities Code Section 2854(a) (1) requires adoption of its proposal, and that the rates charged customers with large solar systems would not otherwise adequately reflect the costs they allow the utility to avoid. Solar Alliance believes that demand charges are bad policy for solar customers. Although there would be a cost shift associated with its proposals, Solar Alliance argues this PG&E exaggerated the extent of cost shift and, in any event, such cost shift would not be a subsidy. The Solar Alliance argues that by not expanding the A-6 Solar pilot or to provide for Option R rates, the resulting rate design would deter the installation of solar by not accurately reflecting avoided costs.

This limited expansion of A-6 eligibility to E-19 customers would carry a cost, as the average A-6 rate is significantly higher than the average E-19 rate. Solar customers will only choose the A-6 Solar Pilot if the benefits of the lower demand charges in the A-6 rate exceed the higher overall cost of service under A-6. The 20 MW cap has been reached, but there continues to be demand by

6 See Beach Reply Testimony at 25.

PG&E commercial customers for the A-6 rate. Solar Alliance thus seeks an increase in the A-6 Solar Pilot program to 50 MW.

The Settling Parties agreed to a Schedule A-6 rate close to that proposed by Solar Alliance, and to allow the A-6 solar pilot to continually refill to the 20MW level when there is attrition. Settling Parties other than the Solar Alliance, however, agreed that the solar pilot's 20 MW limit should not be expanded and that a new Option R not be adopted with reduced demand charges. Settling parties believe that such measures would cause additional cost shifting to other customers beyond the subsidies already created by the existing 20MW A-6 Solar Pilot.

The A-6 rate generally has applied to MLLP customers with peak demands less than 500 kW. In Phase II of its last GRC (A.06-03-005), PG&E agreed to develop a pilot program to allow commercial net energy metered solar customers to avoid demand charges. Under the pilot program, customers in the E-19 rate class with loads between 499 kW and one MW who install solar photovoltaic (PV) systems can elect the A-6 rate for up to 20 MW of solar generation. The Commission approved this pilot in Decision 07-09-004.

The MLLP Settling parties oppose the expansion of the A-6 Solar Pilot and creation of a new Option R rate schedule, arguing that doing so would create additional revenue shortfalls Under the MLLP Settlement Agreement, Schedules E-19 and E-20 include time-differentiated demand charges in the on-peak and partial-peak periods for both generation and distribution. Nearly 100% of the estimated generation capacity marginal cost is collected in these two demand charges on Schedules E-19 and E-20.

Distribution on-peak and partial-peak demand charges reflect the marginal cost of primary distribution capacity. Primary distribution capacity is the only time-differentiated portion of distribution cost, because it is the only portion related to peak-period demands on distribution level facilities. The rate designs for Schedules E-19 and E-20 collect approximately 80 percent of the assigned primary distribution related revenue through demand charges. There are only about 3,000 large businesses and commercial or governmental customers for whom service under Schedules E-19 or E-20 is required, representing about the top one-half of 1% of all customers taking service under the Small, or MLLP Tariffs. Rate design based on marginal costs establishes demand charges (in units of dollars per kW) for these services. The rates applicable under Schedules E-19 and E-20 have been developed to be nearly fully cost-based.

Demand charges are designed to recover fixed, capacity-related costs that are not avoided by fluctuations in a customer's energy usage. PG&E argues that because Solar Alliance's proposal would require the collection of demand-related costs through volumetric energy charges, such a rate design would not be cost-based.

To the extent that a solar installation causes demand to drop in the relevant time periods, the customer can reduce the demand charges it must pay. However, if demand remains, the customer pays a demand charge.

Solar Alliance witness Beach testified that certain elements of the existing E-19 and E-20 rate design, such as the demand charges for generation capacity and non-coincident demand charges for distribution costs, do not reflect cost causation for customers who install solar or other types of DG. Solar Alliance claims that installation of customer solar projects allows the utility to avoid generation capacity costs and that customers installing solar are not adequately compensated for those avoided costs under the E-19 settlement rates. Solar

Alliance argues that the non-coincident peak demand is not a reasonable measure of a solar customer's contribution to peak load because of the intermittent and unpredictable nature of the customer's solar output. Solar Alliance argues that the use of non-coincident peak in 15-minute intervals for determining demand charges ignores the diversity of individual solar customers' load patterns on the distribution system. Solar Alliance argues that TOU energy charges spread these costs over all peak hours during a billing period more accurately contribute to upstream capacity costs, particularly for customers with erratic loads, such as customers with behind-the-meter solar generation facilities. Thus, Solar Alliance argues that although solar customers impose fewer costs on the utility system compared to load of regular, non-solar commercial and industrial customers, demand charges prevent solar customers from realizing the benefits of these avoided costs.

Schedule E-19 and E-20 customers who install solar generation receive several subsidies to support this choice, as enumerated in Exhibit 131. In addition to these subsidies, each customer reduces its electricity bill by the amount of electricity or demand it no longer has to have supplied by PG&E.

Solar Alliance provided a calculation in support of its claim that based on a rate structure without demand charges, a solar customer would be able to realize bill reductions that are much closer to avoided costs associated with the solar unit's output on peak days.[7] The example provided, however, only assumes extreme conditions where the customer has the same on-peak demand on cool

---

7 See Beach testimony dated October 6, 2010, Ex. 26, at 24-25.

overcast days as it does on sunny hot afternoons when system loads are at peak levels.

PG&E presented testimony of three witnesses in support of its claim that Solar Alliance's proposed A-6 pilot expansion and Option R proposal are not cost based and would cause additional cost shifting to other customers. The key dispute involved the extent to which demand charges reflect cost causation, as well as Commission policy goals. PG&E argues that generation, transmission, and distribution capacity costs are properly collected in demand charges for large commercial and industrial customers. PG&E contends that switching to a volumetric rate to recover such costs would enable customers to avoid paying for their share of these costs, and shift cost recovery to other customers. PG&E claims that the annual subsidy from the availability of the A-6 rate could be approximately $104,000 for every MW installed under the pilot, or approximately $3.1 million per year for the 30 MW expansion of the pilot proposed by Solar Alliance. Actual customer savings could be larger or smaller[8]

The cost shift measures the reduction in revenues from the participating customer (in terms of bill savings) plus any program costs minus avoided costs. The Commission's consultant, Energy Environment Economics, Inc. (E3) used this test when it established that solar installations shift costs to nonparticipants for all sizes for both residential and nonresidential customer installations. When a customer chooses a better rate option, the lost revenues increase.

PG&E also presented an example to support its claim that Option R could produce cost shifting. Assuming a customer with a peak demand of about

---

[8] PG&E/Buller, Ex. 131, at 19, lines 24-29.

550 kW installs a 1 MW PV system, the savings could lower its standard annual bill (excluding customer charges) under Schedule E -9 by $212,000 (from $344,000 to $132,000), based on the proposed MLLP Settlement rates. By reducing demand charges, Option R would further lower this customer's annual bill to approximately $104,000, for an additional annual savings of $28,000. The resulting new subsidy under Option R would be approximately $7 million per year, if the 250 MW cap of DG capacity were to be fully subscribed.[9]

### 3.2.9. Discussion

We conclude that the MLLP Settlement should be adopted, and that the Solar Alliance proposals regarding the A-6 Solar Pilot and Option R should be rejected. The MLLP Settlement has wide support, even though it is not an "all-party" settlement. Rule 12.1 states that "Settlements need not be joined by all parties." The MLLP Settlement Agreement was signed by all but one of the active parties submitting testimony on these issues, including parties whose members include solar customers or those considering solar installations.

We conclude that the Schedule E-19 and E-20 rate design proposed in the MLLP settlement provides for cost recovery in an appropriate manner, consistent with our long-standing policy regarding cost-based ratemaking. The Commission has approved and encouraged use of demand charges for service to PG&E's largest electric customers in multiple decisions dating back to the mid-1970s.[10] The rate structure in the MLLP Settlement generally provides incentives to use energy efficiently and to conserve.

---

9 PG&E/Quadrini, Ex. 131, at 27, line 13 to 28, line 6.

10 PG&E/Bell, Ex. 131. at 5.

We are not persuaded by Solar Alliance claims that the Commission's longstanding policy regarding the use of demand charges has become outdated, or that demand charges are no longer needed, given advances in metering technology, and solar and other DG. Solar Alliance argues that customers with solar cannot control the weather and therefore have no ability to control their demand, and that changes must be made to accommodate these customers

Solar Alliance argues that the Commission is moving to the use of Critical Peak Pricing rates, which use very high energy rates in a limited number of critical peak hours, as a replacement for a portion of a customer's generation demand charges. Witness Beach acknowledged, however that Critical Peak Pricing has nothing to do with non-coincident demand charges, and that it did not eliminate demand charges.[11] Likewise, although the Commission is beginning to make available rates that use real time pricing, incorporating more granular, hourly market prices, this proposed hourly energy rate will be a replacement only for traditional TOU energy rates, and may not affect any demand charges.[12]

Solar Alliance argues that demand charges prevent a solar customer from avoiding generation capacity charges that the solar customer permits the utility to avoid. We are not persuaded that expanding A-6 eligibility and introducing an Option R rate would be cost-justified. We conclude that Solar Alliance's proposals may result in cost shifting to subsidize the solar facilities. The E-19 and E-20 schedules include time-differentiated demand charges in on-peak and

---

[11] Solar Alliance/Beach, Tr. at 1477 line 27 to 1488 line 26.

[12] Solar Alliance/Beach, Tr. at 1479 line 21 through 1480 line 5.

partial peak periods for both generation and distribution costs. Capacity-related costs occur at the distribution, transmission and generation levels of the electric grid. Because generation, transmission and primary distribution infrastructure serve many customers, an individual customer's contribution to these capacity costs depends on the customer's contribution to the coincident peak at the corresponding level of aggregation. For the portion of the distribution system that is closest to the customer, the capacity required to serve the customer is driven by the customer's non-coincident peak demand. Because the distribution capacity costs for infrastructure near the customer are a function of the customer's maximum demand, non-coincident demand charges are an appropriate mechanism for collecting the revenues needed to cover these costs. Because an individual customer's peak load may not coincide with system peak loads, demand charges, even peak-period demand charges, to collect revenues for generation, transmission and primary distribution capacity costs only approximate customers' contributions to system peaks.

The demand charge structure in the MLLP settlement is consistent with established rate design principles for large customers. The rate designs for Schedules E-19 and E-20 collect approximately 80 percent of the assigned primary distribution related revenue through demand charges.[13] As noted by PG&E, primary distribution capacity is the only time-differentiated portion of distribution costs because it is the only portion that is related to peak-period demands on PG&E's distribution-level facilities.

---

[13] PG&E/Bell, Ex. 131, at 9, lines 17 to 23.

The Schedule A-6 Solar Pilot currently has a 20 MW cap on participating load. Both of Solar Alliance's proposed rate options are designed to reduce or eliminate the use of demand charges, and instead collect larger portions of costs in more readily avoidable energy (per kWh) charges. An additional number of customers with very large electric loads would receive service under a tariff that was originally designed to meet the needs of much smaller commercial customers (i.e., with demands of 20-50 kW). Solar Alliance's proposed expansion of the A-6 Pilot from 20 MW to 50 MW would more than double the size of the existing subsidy.

An additional consequence of Solar Alliance's proposed change is to allow solar projects with significant power exports to the grid to receive much larger payments for their exports during the entire summer on-peak TOU period. With this option, customers with solar can use their power generated on site to first reduce their demand, and thereafter they can export any surplus power. They receive a credit for the full retail value of those exports. The credit for such exports includes a value for generation, transmission and distribution, and public purpose charges.

Solar Alliance is seeking to increase peak rates provided to solar customers for exports from the 13 cents per kWh rate in E-19 to a price of 23 cents per kWh under Option R, or over 40 cents per kWh under A-6.[14] We conclude that solar customers on net metering are currently receiving enough compensation for the costs they allow the utility to avoid. For customers on net metering, whenever the solar generator produces more than the customer needs at the time, the

---

14 Solar Alliance/Beach, Tr. at 1500 line 6 to 1501, line 18.

exports to the grid are credited to the customer at the full retail rate. The credit offsets bills for any energy needs the customer has taken over a 12 month billing period. If tariffs with high volumetric rates are in place when a customer's solar system is exporting, that customer can earn large bill credits during those times. Although that credit is offset against the charges customers incur for use from the system in other hours, these later hours often occur when retail rates are much cheaper. Thus, an exported kWh during the peak period can offset more than one kWh needed later.[15]

After issuing our Cost Benefit Decision in 2009, and relying on that decision, the Commission in 2010 issued a Report to the Legislature on the costs and benefits of net metering, which concluded that net metering does indeed provide a subsidy to net metering customers which is paid for by non-participating customers[16] Costs shifted to other customers included the cost of rebates, avoided bills, program administrative costs, metering and interconnection costs. The total costs shifted from solar customers to nonparticipating customers averaged over 21 cents per kWh.[17]

Customers will only choose to participate in the A-6 pilot if their bills are lower on the A-6 rate than on the E-19 rate. Nonparticipating customers will have to make up the lost revenue.

---

15 PG&E/Buller, Ex. 131, at 17 and 19 line 1 to 20 line 9; PG&E/Quadrini, Ex. 131, at 25, lines 19-24; Commission's Report on the Cost of Net Metering, section 3-1, at 18-21.

16 This report was admitted in evidence as Exhibit 140. The full report is posted on the Commission's web site. ("CPUC Solar Report").

17 CPUC Solar Report, Ex. 140, at 90.

If the customer's DG unit goes out of service during the relevant period or the sun is obscured by clouds and the customer either chooses not to reduce its load while the generation is out of service (or is unable to), it imposes a demand on the system. Solar customers' use of the utility system actually causes some costs that do not vary with usage, and demand charges are designed to cover those costs.[18] The E-19 solar customer should pay for that demand.

Solar Alliance argues that installation of customer solar projects allows the utility to avoid generation capacity costs and that customers installing solar are not adequately compensated for those avoided costs under the E-19 settlement rates. We recognize that solar customers' facilities contribute to reduced utility generation capacity costs. We conclude, however, that E-19 solar customers' bill savings from solar installations already provide appropriate compensation for their contribution to reduced capacity costs.

Solar Alliance argues that installation of customer solar projects allows the utility to avoid Resource Adequacy costs. In the Commission-sponsored evaluation of the CSI program, E3 included avoided Resource Adequacy costs as a benefit from the solar installation. Despite inclusion of avoided generation capacity costs (and all the other avoided costs), the identified benefits to other ratepayers were less than the costs of the solar installation (to other customers).[19]

We conclude that E-19 customers already receive appropriate compensation for this contribution in the form of bill savings from their solar installation. We find that E-19 and E-20 customers who install solar generation

---

18 PG&E/Quadrini, Ex. 131, at 23 line 7 to 25 line 14.

19 CPUC Solar Report, Ex. 140, at 90, A-28.

to help meet their energy needs receive several subsidies to support this choice. PG&E enumerated these subsidies in Exhibit 131,

The E-19 rate was designed for these large customers and the revenue allocation and rate design for this class was based on their taking service under the E-19 rate. The A-6 rate was designed for an entirely different set of smaller customers.[20] Solar Alliance acknowledged there would be a cost shift associated with its proposals, but argued that this cost shift would not be a subsidy.

The Commission consultant, E3 found that the benefits to non-participating ratepayers were less than the costs of solar installations.[21] Solar Alliance Witness Beach included "behind-the-customer-meter" solar projects on the supply side of the Resource Adequacy calculation, even though they do not qualify to be counted there because the necessary contracts have not been signed, and because deliverability assessments required for such credit have not been completed.[22] Witness Beach did not know how much the utilities might be paying to meet their Resource Adequacy requirements, and seemed entirely unclear on how to separate out generation capacity, energy, and Resource Adequacy costs

Customers who install solar are already being compensated for any contribution to avoided transmission and distribution investments. In support of its claim that installing solar allows a utility to avoid building any T&D lines, Solar Alliance states that the Itron Ninth Year impact report "calculates peak

---

20 PG&E/Bell, Tr. at 1337, lines 6-21.

21 CPUC Solar Report, Ex. 140, at 90, A-28.

22 See Solar Alliance/Beach, Tr. at 1454, lines 10-18, at 1456, lines 9-23. See also D.09-06-028 at 42-45 and 50, cited by Mr. Beach at Ex. 136, at 9, line 15.

reduction factors of 30% to 42% of the PV nameplate."[23] The Itron report actually finds peak demand reduction factors on various feeders ranging from zero to 80% of nameplate. This finding is consistent with Exhibit 138, which showed peak demand impacts ranging from 6% to 55%, depending on what time of day the utility system peak occurred. Thus, peak impact alone is not enough to ensure T&D deferrals.

As explained by PG&E, adding solar in one area does not reduce T&D needs in another area, and may not even help in the area where it is installed. If there is no need for T&D upgrades in an area, there are no such upgrades to avoid. Similarly, if the line segment serving this load must be used to export an equivalent amount of power and provide standby when the solar unit is not producing, then adding solar panels does not avoid new investment. Instead, additional requirements must be met, other than simply bringing a solar unit on line, before T&D upgrades will be avoided.

The Joint Solar Parties do not object to the Settlement's proposed Schedule E-19 and E-20 rate design generally, nor to its proposed TOU periods or shapes. We conclude that the MLLP Settlement rate structure provides appropriate incentives to use energy efficiently and to conserve. There is nothing about the rate design for Schedules E-19 or E-20 in the Settlement which violates SB 1. E-19 and E-20 customers are continuing to install solar systems without an A-6 rate or an Option R rate available to them. The business of selling and installing solar panels in PG&E's service territory can and will continue unaffected by approval of the MLLP Settlement.

---

23 Solar Alliance Opening Brief at 11-12 and fn. 22.

In conclusion, we find the MLLP Settlement to be reasonable. Except for the contested issues addressed and resolved above, the MLLP settlement has broad support among multiple parties. Based on the standard of review discussed further in Section 4, we find that the MLLP Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest. We adopt the MLLP Settlement Agreement, and authorize PG&E to implement changes in rates in accordance with the terms of the MLLP Settlement Agreement.

While we do not adopt the Solar Alliance proposals in this proceeding, we believe that additional study is warranted examining the demand charges in the E-19 and E-20 tariffs, and the extent to which those demand charges may penalize customers with erratic loads by overcharging them for their contributions to systems peaks. We thus direct PG&E to complete a cost study prior to its next GRC Phase 2 application examining this question. The study should evaluate whether an Option R rate for E-19 and E-20 customers that shifts a portion of generation and distribution demand charges to TOU energy charges may more appropriately recover capacity-related costs from customers with on-site solar generation facilities.

The study should assess data on the correlation of solar output and solar customer-generator loads at various levels of geographic aggregation and how the correlation, or lack of correlation, affects their contribution to capacity costs. PG&E should estimate the additional compensation that may accrue to customer-generators as a result of higher TOU energy rates under net energy metering (NEM), and discuss whether the higher rates of NEM compensation result in an additional subsidy for customer-generators, and discuss the feasibility of designing optional rates that offer different rates for energy consumption and net energy production during discrete TOU periods.

### 3.3. Small Light & Power Rate Design Settlement

Multiple parties entered into a Small Light and Power (SLP) settlement regarding rate design for SLP customers.[24] Subsequent to execution and filing the SLP Settlement on April 8, 2011, the Settlement Parties agreed to revision of Section V. B. 4 to modify the implementation date of the threshold delineation between the SLP and MLLP classes.[25] The First Amendment replaced the original Section V. B. 4 terms with revised terms which simplify implementation of the delineation between the SLP and MLLP classes. Instead of separate implementation dates for customers over 100 kW and customers over 75 kW, the First Amendment starts implementation for all eligible customers over 75kW in November 2012 and, if mandatory TOU rates are adopted, coordinates the implementation of the customer's transition under the class delineation with the customer's transition to mandatory TOU rates. The SLP Settlement, as amended on September 22, 2011, incorporates the following proposals:

#### 3.3.1. Use of Illustrative Settlement Rates:

Rates to collect the revenue allocated to the SLP customer class under the March 14th settlement are to be designed consistent with the illustrative settlement rates in Exhibit A to the Settlement Agreement.

---

[24] The Parties sponsoring the SLP Settlement are: CAL-SLA; DRA; PG&E; and TURN.

[25] The SLP customer class encompasses and is defined as PG&E customers taking service under Schedules A-1, A-1-TOU (Time-of-Use), A-6, A-15, TC-1and E-CARE, as described in Exhibit PG&E-14 Chapter 4.

#### 3.3.2. Updating the SLP Rates

The applicable SLP rate schedules are to be updated upon implementation of the settlement, using the methods underlying the illustrative settlement rates presented in Exhibit A to the Settlement Agreement.

**a) Customer charges**:

For Schedules A-1, A-1-TOU, and A-6, customer charges will be set at $10 for single-phase service and $20 for poly-phase service. For Schedules A-15 and TC-1, use the $10 single-phase customer charge.

b) **Revenue Neutral Design**:

Schedules A-1, A-1-TOU, A-6, and A-15 shall be designed on a revenue-neutral basis, with Schedule A-15 paying an additional $25 per month special facility charge for direct current (DC) service.

#### 3.3.3. Schedule A-6 Rate Design:

Allocate 50 percent, rather than 100 percent, of PG&E's proposed non-marginal distribution costs to the flat adder, resulting in a compromise level of TOU differentiation close to that proposed by Solar Alliance. In addition, slightly modify off-peak rates in each season by altering the seasonal distribution allocation to better meet the original objectives of both DRA and the Solar Alliance to set the summer off-peak rate approximately 1 cent per kWh above the winter off-peak rate.

#### 3.3.4. Kilowatt Threshold Delineating Small from Medium L&P

The SLP Settling Parties agree to delineate the threshold between the Small L&P and Medium L&P customer classes as follows:

##### a. First Wave of Threshold Phase-In

Require L&P customers over 75 kW to migrate off SLP Schedules A-1, A1-TOU and A1-PDP only after the customer has 12 months of interval data. This is expected to move approximately 3,000 Schedule A-1, A1-TOU and A1-PDP customers over 75 kW to Schedule A-6, A6-PDP, A10-TOU, A10-PDP, E-19V or E-19V-PDP. Non-TOU A-10 may also be available if the customer is not yet subject to default to TOU as ordered by D.10-02-032.

The transition date for the First Wave would be the later of: (a) November 1, 2012 or (b) the date customers have 12 months of interval data available, provided however, that if the Commission mandates mandatory TOU for these customers beginning November 1, 2012, each customer's transition under the 75 kW threshold articulated here would occur on the same day as the transition to mandatory TOU. In the event that kW data is not available, 150,000 kWh per year shall be used as a proxy for the 75 kW threshold.

#### b. Second Wave of Threshold Phase-In

Further reductions in the kW cutoff threshold may be reconsidered in PG&E's 2014 GRC Phase 2 proceeding. To facilitate such consideration, DRA agrees to provide PG&E with a lower kW cutoff threshold approximately 9 months in advance of the filing date of PG&E's 2014 GRC Phase 2 application. At that time, DRA and PG&E will confer and attempt to reach an agreement on a lower cutoff kW threshold. If no agreement is reached, PG&E then agrees to make a good faith effort to analyze the DRA and PG&E kW cutoff thresholds in parallel. PG&E agrees to provide the following information to DRA, within 60 days after PG&E files its 2014 GRC Phase 2 application:

i. An alternate revenue allocation, reflecting a lower maximum kW threshold or kWh proxy for A-1, A1-TOU, and A1-PDP eligibility, as may be proposed by DRA in the 2014 GRC Phase

2, and assuming the customers migrating from A-1 will move to A10-TOU; and

ii. Billing determinants needed to compute correct rates for A-1, A10-TOU, and related classes affected by a proposal (if any) by DRA to lower the maximum kW eligible for A-1, A1-TOU and A1-PDP service.

### 3.3.5. Schedule A-15 DC Meter Issue:

Customers on Schedule A-15 whose DC meter is not functioning properly and for which no utility grade replacement meter is available, agree to have their DC usages estimated for the purposes of billing. This will be done by means of a special agreement under Schedule A-15. A customer's usage may be estimated by: (a) providing that customer with a replacement non-revenue-quality DC meter, or (b) installing a temporary metering device to establish an average fixed monthly usage, or (c) calculating an average fixed monthly usage based on motor sizes, equipment capacity ratings, end-uses, load factor or usage patterns, site inspections or surveys, and records of historical usage. No back-billing for undercharges for non-registering meters would occur.

### 3.3.6. Schedule E-CARE

The settlement adopts the Schedule E-CARE rate design for Commercial CARE customers set forth in Exhibit A to the SLP Settlement. This sets appropriate per-kWh rate discounts by rate schedule to establish parity with the level of average CARE rate discounts in the residential sector, as updated to reflect the new CARE Tier 3 rate, $2.40 per month CARE customer charge, and baseline quantity changes, if adopted by the Commission. Should the residential rate design measures and associated CARE discounts adopted by the Commission differ from those assumed in the settlement, the Commercial CARE rate per kWh discounts will be revised to achieve any parity with the adopted average residential CARE rate discount. The discounts will also, on the same basis, commensurately change with each future electric rate change.

#### 3.3.7. Annual Billing:

Rather than adopt the City of Hercules' proposal for annual billing, rather than monthly billing, for low-usage customers, the settlement addresses these concerns through the agreed lower single-phase customer charge, as well as consolidated billing, and online e-bills, which are available upon request.

#### 3.3.8. PDP Refinements:

The settlement adopts the refinements to Schedule A-1-TOU and Schedule A-6 PDP rates proposed by PG&E in Chapter 9 of Exhibit (PG&E-14).

#### 3.3.9. Schedule TC-1:

The settlement adopts an intra-class revenue allocation that reflects the fact that TC-1 customers have very high load factors compared to all other SLP customer.

#### 3.3.10. Discussion

We find that the SLP Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest. We adopt the SLP Settlement Agreement without modification, and authorize PG&E to implement changes in rates in accordance with the terms of the SLP Settlement Agreement.

### 3.4. Remaining Residential Rate Design Issues

The majority of PG&E's residential rate design issues were decided in D.11-05-047. The three remaining residential issues are: (1) natural gas baseline quantities; (2) Schedule ES multifamily master meter discount; and (3) Schedule ET mobile home master meter discount. The first two of these issues were addressed in an all-party settlement, as discussed below. The Schedule ET discount was contested, and we resolve the disputed issues in Sec. 3.4.2. below.

#### 3.4.1. Schedule ES and Natural Gas Quantity Baseline Settlement

Settling Parties (i.e., PG&E and TURN) seek approval of the supplemental settlement agreement resolving the Schedule ES (ES) and Natural Gas Baseline Quantity (GBQ) issues -- two out of three of the remaining rate design issues -- for the residential customer class (ES/GBQ Settlement Agreement). The supplemental Settlement Agreement uses the revenue allocation agreed to in the March 14 Settlement and addresses rate design issues that were not resolved in the March 14 initial settlement.

This settlement is not contested by any party. Based on our standards for the review of settlements, as discussed in Sec. 4 below, we conclude that this settlement is reasonable and accordingly adopt it without change.

The settlement incorporates PG&E's uncontested proposals for natural gas baseline quantities set forth in Exhibit 14, Chapter 3, page 3- 4 line 9 through Table 3-6 on page 3-8 (see excerpted table set forth in Appendix A to the ES/GBQ Settlement Agreement). These natural gas baseline quantities, together with any revenue neutral rate adjustments, would be implemented in one step on the first day of the next available season after the effective date of the final decision regarding the Settlement.

The ES/GBQ Settlement incorporates PG&E's proposals for the Schedule ES discount -- which relates to electric multifamily service master metered customers [26] with certain updates and revisions as set forth below. TURN identified several modifications to the master meter discount calculation for Schedule ET that also apply to Schedule ES. No other party took a position on the Schedule ES discount, and the settlement is a compromise of TURN's and PG&E's positions relating to Schedule ES.

The ES/GBQ Settling Parties propose adoption of a base ES Master Meter Discount of $2.32 per space per month, which reflects the following revisions and updates (line 32 of Table 3-13 in the above-cited testimony.)

The revised ES discount recognizes that the equipment cost for a master meter is greater than for a residential meter, and thus it is appropriate to use a medium light and power (ML&P) meter at secondary voltage as the proxy for the master meter. Primary and secondary distribution costs have been removed from the connection costs used in developing the revised, settlement ES discount, to be consistent with PG&E's MCAC methodology

Transformer and service equipment costs and related ongoing costs for both the tenant meter and master meter have been removed from the revised ES discount, because tenant service and transformer costs are not avoided and no offset for these costs is needed for the master meter. Whether master metered or individually metered, the service extension termination point is typically the same. What differs is whether the connection termination point is a single master meter or multiple residential meters in a grouped configuration.

For ongoing costs used in developing the revised ES discount, setting parties agree to adjust "Other Account 903" expenses that are included in the

---

[26] See Exhibit 14, Chapter 3, Table 3-11 at 3-14, and as explained at 3-9 line 14 through 3-13 line 18.

billing and collection cost category for the tenant meters to reflect as avoided costs only the costs for Account Services, Local Office Transactions and Neighborhood Payment Centers.

For ongoing costs for the master meter, meter services costs and meter reading costs are applied consistent with the ML&P proxy for the master meter. Billing and collections costs are consistent with a SLP meter to reflect the billing process for a master metered multi-family development as compared to the billing of ML&P customers. Attachment 2 to the Settlement Agreement provides conforming calculations to update the Table 3-13 derivation of the Schedule ES submetering discount. To determine a Net ES Discount, the revised Base ES Discount in the settlement, once adopted, is to be adjusted to reflect the Diversity Benefit Adjustment. The Diversity Benefit Adjustment will need to be recalculated using rates in effect at the time the ES submeter discount is implemented, and should be set to the Diversity Benefit Adjustment calculated for PG&E Schedule ET multiplied by a factor of 58 percent.

Thus, although the Base Discount proposal adopted here will go into effect for this rate case cycle, without further modification, the Net ES Discount figures set forth here are merely illustrative:

| | |
|---|---|
| Base Monthly ES Discount: | $ 2.32 |
| Less Diversity Benefit Adjustment: | $ 2.86 |
| Net ES Discount: | $(0.54) |

#### 3.4.2. Schedule ET Mobile Home Park (MHP) Master Meter Discount

We next resolve the one remaining residential rate design dispute, namely the Electric Mobile Home Park (MHP) Service master meter ET rate discount. This issue was not the subject of a settlement agreement, but reply testimony was presented by TURN and WMA. Under Schedule ET, electricity is delivered to a single MHP master meter (MM) customer and then delivered to end users at individual mobile homes through a sub metered private distribution system.

The MHP MM discount is required per Public Utilities Code Section 739.5(a), as affirmed in D.05-04-031:

> The discount is intended to reimburse the MHP owner for the reasonable average cost of providing submetered service. However the statute also imposes a cap on the discount. It is not to exceed the average cost that the utility would have incurred in providing comparable services to the tenant directly….[T]he average cost the local utility would have incurred in directly serving the MHP tenants determines the level of the discount.[27]

The ET discount compensates the MM MHP owner for costs that the utility avoids because the MM MHP owner has submetered all the tenants' spaces rather than have the utility directly serve them. This use of utility avoided costs as a cap or proxy to implement Section 739.5(a) is necessary because park operators do not keep adequate records to implement the plain language of the statute "to cover the reasonable average costs to master-meter customers of providing submeter service."[28]

PG&E's MM discount methodology as presented in its January 7, 2011 update testimony, dates back to PG&E's 2003 GRC, and is based on a marginal cost based calculation to reflect PG&E's avoided costs in electric submeter discounts. Until now, PG&E has not performed an in-depth review of the 2003 GRC settlement methodology.

---

[27] See D.05-04-031, mimeo., at 3.

[28] See Section 739.5(a); and D.04-11-033, mimeo., Findings of Fact 5 and 6.

PG&E calculated the ET discount based on the categories of cost avoided by PG&E when the master metered MHP is submetered. PG&E calculated the discount pursuant to guidance in D.04-04-043 and D.04-11-033 (PG&E, Troup TR. 1097, lines 23 – 26.)[29] The resulting net monthly submeter discount proposed by PG&E, after adding the uncontested line loss adjustment of $1.02 and subtracting the illustrative Diversity Benefit Adjustment (DBA)[30] of $5.15, is $2.40 per space.

WMA contests PG&E's proposal for electric master meter ET discounts, and proposes a master meter capped discount of $17.30 per space per month and an uncapped discount of $22.30 per space per month.

TURN also originally differed with PG&E as to the Schedule ET discount. Based on PG&E's rebuttal and surrebuttal testimony incorporating many of TURN's recommendations, however, TURN now supports PG&E's final ET discount proposal with the caveat that resolution of contested issues in PG&E's favor will apply only to the master meter discount in this proceeding. TURN differs with PG&E as to the escalation and discount rates, but the difference is not significant for purposes of calculating the ET discount (amounting to a difference of $0.01/space per day). TURN thus stipulates to PG&E's approach solely for the purpose of calculating the ET discount, but intends to litigate this

---

29 D.04-0443 and D.04-11-033, issued in the MHP Submetering Discount Rulemaking 03-03-017; Investigation 03-03-018, identified categories of costs avoided by electric and gas utilities when mobile home park tenants are served by a master meter owner.

30 The Diversity Benefit Adjustment is intended to ensure that the MHP operator does not realize a revenue windfall by individually billing submetered park tenants at prices and quantities that exceed the prices and quantities billed to the MHP operator by PG&E at the master-meter level.

issue in future proceedings and does not want the establishment of the ET discount to prejudice any party's ability to raise this argument in a subsequent case. To the extent that the Commission adopts PG&E's discount, TURN requests that the embedded escalation and discount rates not be approved for any other purpose or deemed precedential in any respect.

The table below summarizes the parties' final differences regarding proposals for the ET monthly base discounts, after reaching agreement on several issues. PG&E and TURN propose a base Schedule ET discount of $6.53. Once the necessary adjustments have been made as all parties agree -- namely, adding to the base discount PG&E's uncontested line loss adjustment and subtracting the now-uncontested illustrative DBA of $5.15 -- the proposed net discounts, range from $2.40 to $22.30 as follows:

| ET Submeter Discount ($/Month/Unit) | PG&E (capped) | TURN (capped) | WMA (capped) | WMA (uncapped) |
|---|---|---|---|---|
| **Base Discount** | 6.53 | 6.53 | 21.43 | 26.43 |
| **Line Loss Adjustment (Add)** | 1.02 | 1.02 | 1.02 | 1.02 |
| **DBA (Subtract)** | (5.15) | (5.15) | (5.15) | (5.15) |
| **Net Discount** | 2.40 | 2.40 | 17.30 | 22.30 |

PG&E's Schedule ET monthly net discount is currently $11.54, and dates back to a 2003 GRC settlement among several parties. The discount was maintained in PG&E's 2007 GRC, as also agreed to in an all-party settlement. In its current application, PG&E proposed to use the same methodology previously applied in its 2007 GRC.

WMA argues that PG&E's proposed Schedule ET discount is understated because it relies upon 2003 data instead of more current data and assumptions as applied to other PG&E rate proposals in this application. WMA also argues that the Schedule ET discount should be scaled up to the average cost of service. We address the contested differences between parties in Section 3.5.2.

We adopt the following uncontested input assumptions for purposes of calculating the Schedule ET Discount.

### 3.4.3. Uncontested Proposals

#### 3.4.3.1. Escalation Factors

PG&E, TURN, and WMA agree on the set of escalation factors to apply to the marginal cost inputs for the purpose of calculating the MHP submeter discount. PG&E proposed escalation factors to adjust its new connection equipment costs from 2003 to 2011 dollars using labor (O&M) escalation specific to PG&E. PG&E, Exh. 105, p. 1-11, lines 1-20.) The parties have agreed that PG&E's proposed escalation factors should be applied to submeter discount cost inputs in this proceeding. We thus find these agreed-upon escalation factors to be reasonable for use in the submeter discount calculation.

#### 3.4.3.2. Line Loss Adder.

The line loss adjustment represents the estimated cost in terms of the electricity that is ordinarily lost when it is transmitted across the lines within the MHP to distribute energy from the master meter to all of the individual submetered tenants. PG&E, TURN, and WMA have all stipulated to a value of $1.02 per space per month for the line loss adjustment in all of their tables and exhibits presenting the derivation of the Schedule ET master meter discount.[31] Accordingly, the net submetering discount shall reflect the unopposed line loss adder of $1.02 per space per month.

#### 3.4.3.3. Illustrative Diversity Benefit Adjustment

PG&E proposes a $5.15 per space per month illustrative Diversity Benefit Adjustment (DBA) to be recalculated upon implementation. The DBA is designed to ensure that MM MHP operators do not receive excess revenues from billing tenants at higher-priced tiers than occurs for the tiered usage billed at the master meter level. [32] TURN supports PG&E's proposal. WMA witness, McCann, clarified that WMA is not proposing in this proceeding to eliminate the DBA. WMA accepts the $5.15 per space revised illustrative DBA proposed by PG&E, as well as the methodology used to develop it.[33]

We adopt PG&E's unopposed illustrative DBA of $5.15 and the methodology used to calculate it, subject to update after this decision is adopted based on rates and revenue requirements in effect January, 1, 2012 when the newly adopted ET discount and the DBA will be implemented.

#### 3.4.3.4. Account 903 Cost Adjustments

The Parties agree in principle that MM MHP owners should not receive a credit for utility costs that are still incurred by PG&E despite it not having to directly service each MHP tenant. Accordingly, all parties support TURN's proposed adjustments to Account 903 to exclude from the submeter discount

---

31 PG&E Exhibits 101, 105, and 107; TURN Exhibit 112; WMA Exhibits 115, 116, 117, 120.

32 PG&E, Exh. 107, at 2-1 to 2-6.

33 WMA, McCann, TR. 1184, lines 14-19.

costs that are still incurred when serving only the master meter and not directly serving all the tenants.

#### 3.4.3.5. Minimum Average Rate Limiter

PG&E proposed that there be no change to the Schedule ET Minimum Average Rate Limiter (MARL) methodology adopted in PG&E's 2007 GRC Phase 2 proceeding. No other party opposed this proposal.[34] (Thus, we affirm that the current MARL method adopted in D.07-09-004, Appendix B, Term H, will remain in effect throughout this 2011 GRC Phase 2 cycle.

#### 3.4.3.6. Secondary Voltage Transformer Costs for MHP Master Meter Connection

WMA agrees to the use of ML&P connection costs at secondary voltage as the proxy costs for the MHP master meter connection. The parties agree about what transformer master meter connection costs should be included in the submeter discount calculation. Witness McCann reflected this change to his calculations in late-filed Exhibit 120. Thus the parties now agree to use ML&P (Schedule A-10) connection costs at secondary voltage as a reasonable proxy for the MHP master meter connection costs. We adopt it.

#### 3.4.3.7. Weighted After-Tax Real Economic Carrying Charge Adjustment

TURN initially opposed PG&E's proposed weighted after tax adjustment to calculate the real economic carrying charge (RECC). (TURN, Exh. 114, p.1.) PG&E used an after-tax discount rate of 7.66% instead of a pre-tax discount rate of 8.79%. TURN argued that PG&E's proposed discount rate, which reflects the

---

[34] PG&E, Exh. 105, at 3-13, lines 26-33.

tax-deductibility of bond interest, is inappropriate for marginal cost evaluation in this proceeding.

TURN subsequently recognized that the quantified effect on the ET discount is small, with PG&E's proposed after-tax RECC adjustment lowering its recalculated ET discount by less than a penny per space per day (all else equal) relative to TURN's previously proposed pre-tax RECC adjustment. (TURN, Exh. 114, at 1.) However, this issue has significant ramifications in other proceedings relating to utility generation such as resource procurement, energy efficiency, and other utility investment decisions.

TURN thus supports PG&E's proposal of using the after-tax RECC solely for purposes of calculating the ET discount, while not setting a precedent that would preclude this issue from being litigated in other future proceedings relating to different utility costs.

We accept the agreement reached between PG&E and TURN on the limited applicability of the RECC for purposes of this proceeding only as an appropriate and efficient disposition. Accordingly, we shall adopt the RECC for the limited purposes of calculating the Schedule ET discount in this proceeding only. TURN is free to argue the conceptual merits of the issue in a different proceeding without being bound by any precedent from this proceeding.

### 3.4.4. Contested Schedule ET Discount Issues

#### 3.4.4.1. Replacement Costs

WMA claims that PG&E's submeter discount proposal does not adequately provide for replacement costs, does not provide for higher costs of replacements within brownfield developments, and does not adequately address added costs responsibility transferred to PG&E for trenching and substructures under line extension rules.[35] WMA thus proposes to add explicit replacement costs to the submeter discount in addition to replacement costs already implicitly included through the RECC factor. TURN and PG&E, however, argue that PG&E's proposed submeter discount calculation— presented in Table 1-3 in Exhibit 105 (p. 1-39)—already includes the proper costs required by Public Utility Code Section 739.5 as classified by the Commission's guidance in Attachment A of D.04-04-043.

We conclude that WMA's calculation to explicitly add replacement costs to the submeter discount would result in double counting. Replacement costs are already implicitly included in the submeter discount through the RECC factor.[36] The submeter discount proposal supported by TURN and PG&E includes trenching for replacements.

Typically if there is a failure in a direct buried service line, PG&E does not replace the entire direct buried service line, but merely replaces a small section of the service line, generally only requiring a couple of feet to splice it in.[37] Any trenching incidental to replacement of that small section is recorded as Operations & Maintenance. The capital items, such as the conductor, would be recorded as capital and added into rate base.[38] These replacement costs for direct

---

35 WMA, Exh. 115, at 9, lines 10-19; WMA, Exh. 116, at 11, lines 1-16; WMA, Exh. 117, at 5, lines 1-12.

36 PG&E Exh. 105, Question and Answer 19, at. 1-18 to 1-20; TURN, Exh. 113, at 19-20.

37 PG&E, Troup, TR. 1090, lines 20-25.

38 PG&E, Troup, TR. 1091, lines 17-23.

burial systems would be included in the marginal customer cost used to develop the submeter discount.[39]

WMA argues that, because the RECC is applied to the costs of new connections, the RECC method does not capture the added responsibility of trenching and substructure replacement for facilities conveyed to PG&E under Rule 16.[40] Under Rule 16, the applicant conveys ownership (and ongoing maintenance responsibility) to PG&E only for conduits and substructures not on applicant premises (for which the applicant has initial installation cost responsibility). Since services behind the master meter are on the premises of the MHP owner, any conduit and substructures installed per Rule 16 are the responsibility of the MHP owner to maintain and replace if necessary. Not only is the applicant for service responsible for (1) excavation costs for all trenching, backfill and other digging as required, and (2) the costs to furnish conduits and substructures, but the applicant remains responsible for owning and maintaining the conduit and substructures that are on applicant's premises.

#### 3.4.4.2. In-Park Secondary Distribution Capital and Maintenance Costs

WMA asserts that PG&E excluded in-park secondary (or primary) distribution capital and maintenance costs in its submeter discount calculation and that PG&E is reducing the 2011 MCAC by an unspecified amount of the secondary distribution costs.[41] PG&E disagrees that it made such a reduction. The item entitled "Test Year Secondary Dist. ($/kW-Year)," shows the added

---

39 PG&E, Troup, TR. 1091, lines 24-28.

40 WMA, Exh. 117, at 5, lines 1-5.

41 WMA, Exh. 117, at 8, lines 17-19 and lines 20 – 21.

amount of "$0.88." (WMA/McCann, TR. 1193, line 24 to 1194, line 4.) Thus, we find that PG&E properly included in the master meter discount its costs for in-park secondary distribution capital and maintenance.

##### 3.4.4.3. Proposal to Add EPMC Scalar to Avoided Costs

The parties agree that marginal costs should be used in performing their discount calculations, but disagree over the interpretation of "average cost" as it applies to the submeter discount in Public Utility Code Section 739.5(a). PG&E and TURN disagree with WMA's application of an Equal Percentage of Marginal Cost (EPMC) scalar to compute "average cost".

We conclude the EPMC scaler should not be applied to the Schedule ET Discount. The EPMC scalar is designed to ensure that the utility's full revenue requirement is recovered in its rate design. As noted by TURN, however, the EPMC scaler does not reflect the master meter customer's average cost of providing service to their tenants. The EPMC scaler is a method of applying utility costs to distribution costs that are not considered marginal in a marginal revenue allocation method. The scalar reconciles the utility's class distribution marginal cost revenues with the full class distribution revenue requirements because marginal cost revenues rarely, if ever, equal the full revenue requirement

WMA claims that PG&E's submeter discount must be adjusted upward by an equal percentage of marginal cost scaler EPMC to ensure that the ET discount is based on the"average utility costs" and thus well within the legal requirements of Section 739.5. WMA claims that if the EPMC scaler is not included in the calculation of the discount, master meter customers will subsidize non-MHP utility residential customers.

PG&E and TURN oppose scaling up the avoided costs in the MM discount to include additional utility-specific costs not avoided by the utility and not incurred by the MHP operators. Thus, they argue that the concept behind using an EPMC scalar for revenue allocation purposes is irrelevant to the utility's avoided costs resulting from MHP operators' serving their submetered systems.

The utility does not avoid all distribution revenue requirements embedded in authorized levels by not having to install service to and directly meter each MHP tenant. The utility only avoids those direct costs calculated or represented by the pure, unscaled marginal costs of serving a master metered MHP owner instead of each MHP tenant.

Applying an EPMC scalar is inconsistent with the intent of Public Utility Code Section 739.5(a), which covers the average cost incurred by MHP operators subject to a cap equal to the utility's avoided costs, as most recently interpreted in D.04-04-043 and D.04-11-033. (PG&E, Exh. 107, p. 1-8, lines 8-11.) We have never approved using an EPMC scalar for the calculation of an electric submeter MHP discount, and only once approved using an EPMC scalar for the calculation of a gas submeter discount [42] Subsequently, in the multi-utility decision on MM MHP discounts, in D.04-04-043 neither Attachment A (regarding electric discount calculation) nor Attachment B (regarding gas discount calculation) mentions an EPMC scalar.

We find no compelling reason to change our established interpretation of average cost that equates average cost with the costs the utilities avoid by not otherwise directly serving MHP master meter customers. We shall continue to

---

[42] See the 1999 SoCalGas proceeding (D.00-04-060, at 113).

apply the current interpretation and the directives in Attachment A to D.04-04-043.

#### 3.4.4.4. Use of Capped Versus Uncapped Connection Costs in Submeter Discount

PG&E's proposed submeter discount uses PG&E's connections costs for extending new services under Rules 15 and 16 as "capped" by line extension allowances, [consistent with Section 739.5 and as has been done in past calculations of the ET discount].[43]

We conclude that PG&E correctly applies capped costs in calculating the ET discount. The Commission chose to use capped costs when it adopted Attachment A to D.04-04-043. (PG&E, Exh. 123.) Attachment A shows, in Definition 4 that costs which are "not incurred by the utility when it directly serves MHP tenants" are not covered by the discount.

WMA argues that the Commission must decide whether to use in the submeter discount PG&E's connection costs that are capped or uncapped by line extension allowances, per the Commission's authority to interpret Section 739.5, and presents a proposal that the Commission explicitly include the full "uncapped" line extension costs. (WMA, Exh. 116, pp. 1, line 18 to p. 2, line 8.) TURN's and PG&E's submeter discount calculation proposals both use PG&E's connections costs for extending new services under Rules 15 and 16 as "capped" by line extension allowances.

WMA refers to Definitions 1 in Attachment A which 1 defines distribution line extension allowances, as "allowances…granted to Applicants… in accordance with Electric Rules 15 and 16." (PG&E, Exh. 123, Attachment A, p. 1).

---

[43] PG&E, Exh. 105 at 1-18, lines 16-30; TURN, Exh. 113, at 13-15.

Electric Rules 15 and 16, state however, that costs in excess of the allowance are *applicant* costs, and Definition 4 clearly excludes applicant costs from costs to be recovered from the discount. Definition 1 also refers to common areas and pedestals, but Definition 4 bullets 1 and 2 clearly also exclude common area costs and pedestal costs from the costs to be recovered from the discount. Therefore, we conclude that WMA's reference to Definition 1 is irrelevant in the context of Attachment A.

Definition 2 refers to the boundaries of the distribution system and service within the MHP that are recovered through the discount, but already indicates this does not cover the costs of the meter pedestal, its foundation, or meter panel owned by an MHP owner under Rule 16.1.D.1.a. Consequently, these costs are also applicant costs, and are also included in Definition 4 as costs not recoverable from the submetering discount.

#### 3.4.4.5. Use of PG&E's 2003 Access Equipment Cost Data, Escalated to 2011

PG&E's proposed ET discount (supported by TURN) is based on new connection equipment cost data from the PG&E's 2003 GRC, escalated to the 2011 test year.[44] WMA argues that PG&E's figures are out of date and that the 2009 new connection contract data should be used.

Although PG&E used 2009 new connection cost data in calculating 2011 marginal costs used for revenue allocation for the residential class (PG&E, Exh. 25 107 p. 1-11, lines 12-17), the 2009 data from PG&E's 2011 GRC marginal cost work papers are not representative of normal construction costs because such costs were incurred during one of the worst economic downturns since the

44 PG&E, Exh. 105, at 1-2, lines 16-17; TURN, Exh. 112, at 7.

1930's depression era. A major driver during the recent downturn was the financial collapse of the housing market and consequent 25-30 percent unemployment in the construction trades in large part due to the lack of new housing starts.[45] The downturn impacted residential as well as commercial and industrial growth, but hit the residential sector particularly hard. Revenue allocation is an indirect use of such construction cost data; and for revenue allocation purposes, because all customer classes were affected by the economic downturn, all costs may have been to some degree similarly skewed. It is more the relative change in MCAC between classes than the absolute level of MCAC that drive movements in revenue allocation between classes. (*Id*., p. 1-11, line 24 to p. 1–12 line 2.) We thus conclude that the 2009 data is not suitable for use in ET discount rate calculations.

#### 3.4.4.6. Use of Multifamily Connection Costs Versus Residential Class Average Equipment Costs

PG&E's proposed discount reflects use of multifamily new connection costs, as it has done in past proceedings.[46] TURN agrees that MHP submeter tenant costs are comparable to multifamily costs. WMA however, uses the average per-customer cost for the entire residential class.[47]

We conclude that the costs to serve submeter MHP tenants are more comparable to the costs of serving multifamily residential customers than those of serving single family customers. PG&E's residential class average is predominantly comprised of single family households. Thus, the residential

---

45 PG&E, Exh. 107, at 1-2, lines 24-30.

46 PG&E, Exh. 105, at 1-36, lines 13-14.

47 WMA, Exh. 116, at 6, lines 1-7.

class average costs overstate MHP avoided costs and would inflate the ET discount higher than avoided costs, contrary to Section 739.5(a).

MHP tenant units are smaller than the average residential dwelling unit. The average usage for MHP tenants in PG&E's service territory is only about 400 kWh per space per month [48]whereas the overall residential class average usage is much higher, at 560 kWh per customer per month. [49]WMA claims that Rule 1 defines multifamily customers separately from mobilehomes and mobilehome parks and thus the costs of service for mobile homes cannot possibly be the same as for multifamily. Under Electric Rule No. 1, Definitions (Rule 1), a submetered MHP is a single premise, and all of the mobilehomes within it constitute a "group of residential units located upon a single premises" (such as a "court group"), and residency in a mobile home is not "transient" (as with a hotel).

Rule 1 does not define a "Single Family" residence. PG&E construes this to imply that single family residences include any residence that is neither a Multifamily Accommodation, nor "hotels, guest or resort ranches, tourist camps, motels, auto courts, rest homes, rooming houses, boarding houses, dormitories, or trailer courts, consisting primarily of guest rooms and/or *transient* accommodations." (Emphasis added). In addition, Rule 1's definition of a "Premises" can be applied to understand that single family only includes one directly-served meter per commodity for a single family residence on a single family residential lot that includes one dwelling unit. Furthermore,

---

48 PG&E/Coyne, TR. 1130, lines 4-9; WMA/McCann, TR 1211, lines 3-9.

49 PG&E, Exh. 105, at 1-6, fn. 4, PG&E, Troup, TR. 1116, lines 13-16; WMA/McCann TR, 1211, lines 13-16.

Electric Rule No. 18, "Supply to Separate Premises and Submetering of Electric Energy" provides that separate premises must be separately metered, and contains several provisions that distinguish when single family service does not apply Thus we conclude that MHP's costs conform with the Rule 1 definition of a "Multifamily Accommodation."

The typical service lengths from the distribution line to the residential unit are a primary driver of the costs of serving residential customers. Shorter service lengths have lower costs. The typical service length for MHPs (a minimum of 10-- 11 feet) is similar to the weighted average service length for multifamily services (about 10 feet) but not at all similar to the weighted average service length for single family service (about 55 feet), which is much longer than the multifamily and MHP service lengths.[50]

In 2009, PG&E's overall residential class was comprised of about 85 percent single family customers and 15 percent multi-family customers (PG&E, Exh. 106, p. WP 1-9, under 2009 transformer and connection cost percentage), meaning that single family units comprise the bulk of the class. Given this proportion, the weighted average service length for the entire residential class average would be expected to exceed 45 feet, more than 4 times higher than either the multifamily or the MHP service length.

WMA combines secondary and service lengths into a single value in surrebutal Table WMA-4. (WMA, Exh. 117, at 17.) By combining the service length with secondary distribution values, WMA inflates the average service lengths for MM MHPs, which causes inaccuracies.

---

50 PG&E, Exh. 107, at 1-6, lines 3 – 19.

We thus reject WMA's use of all residential as opposed to multifamily new connection costs for MHPs. WMA's approach overstates the avoided costs from submetering and artificially inflates the discount. PG&E's use of multifamily new connection costs is the most reasonable estimate of the connection costs that the utility avoids by not directly serving MHP submetered tenants.

#### 3.4.4.7. Study Regarding Costs of Serving Mobile Home Park Customers

As noted by TURN, many of the debates over the submeter discount relate to disagreements over the costs incurred by the utility for directly serving mobile home parks. To address this issue prospectively, we adopt TURN's recommendation that PG&E collect information on the actual costs of serving these customers and present this data in its next Phase 2 GRC proceeding. Once such information is collected, the Commission can more accurately assess the average cost that the utility would have incurred in providing comparable services directly to the users of the service. Parties will then be able to propose a submeter discount based on the actual costs incurred by PG&E to provide comparable services.

### 3.5. Streetlighting Rate Design Settlement

Settling Parties submitted a Streetlighting (STL) Rate Design Settlement Agreement on June 3, 2011. The STL Settlement uses the revenue allocation agreed to in the March 14 Settlement and addresses Rate Design issues that were not resolved in that initial settlement. The STL Settlement's outcomes are complementary with those of the March 14 Settlement.

A motion for adoption of an amended STL Settlement was filed on October 17, 2011. The Amended STL Settlement makes minor changes to the STL Settlement filed on June 3, 2011, to add an annual Commission reporting requirement, add additional contract requirements, and to have consistent terminology when referencing the customer or PG&E. These changes bring the previously filed STL Settlement into conformity with the changes made in Commission Resolution E-4221 which approved the contract on September 22, 2012. This First Amendment does not affect any other provision in the STL Settlement or the Settlement in A.10-03-014 filed with the Commission on March 14, 2011 (March 14, 2011 Settlement), to which the STL Settlement is supplemental.

The Amended STL Settlement, attached in the Appendix of this decision, includes all of the changes approved in Resolution E-4221. Adoption of these Amended STL Settlement documents, in place of those originally filed in June, will ensure consistency with the modified Special Contract the Commission adopted in Resolution E-4221. The reasons supporting Commission adoption of the Amended STL Settlement remain the same as those set forth in PG&E's June 3, 2011 motion for approval of the original STL Settlement, at pages 6 to 8, which are incorporated herein by reference. The STL settlement includes the following fundamental components:

#### 3.5.1. Updating Basic Rate Designs

Each of the applicable STL rate schedules are to be updated upon implementation of this settlement, using the methods underlying development of the settlement's illustrative streetlight rates. These include the facility charge rates for Schedules LS-1, LS-2, OL-1 and City and County of San Francisco, as presented in Attachment 1 to the STL Settlement. In addition, the agreed total rates for each lamp type for Schedule LS-1, LS-2 and OL-1, as presented in Attachment 2 to the STL Settlement, which are based on the revenue allocation settlement presented in the March 14 Settlement Agreement, are reasonable and should be adopted.

### 3.5.2. Pilot Program for Network Controlled Dimmable Streetlights.

CAL-SLA proposed a new LS-4 rate for expected upcoming installations of an emerging network controlled dimmable streetlight technology, including separate chapters of testimony authored by the Cities of San Jose and Oakland who are each pursuing future installations of such technology. PG&E expressed technical and cost concerns with adoption of an entirely new rate for this still emerging technology.

The STL Settling Parties agree that it is reasonable for the Commission to instead adopt a Pilot Program for Network Controlled Dimmable Streetlights under the existing LS-2 rate, as set forth in detail in Attachment 3 to the STL Settlement.

The revised STL Agreement with minor modifications made at the request of the Energy Division with the concurrence of the Settlement Parties replaces the original Attachment and Appendix A. This ensures consistency with the minor modifications made when the Commisison adopted Resolution E-4221 on September 22, 2011 approving the Special Contract for Unmetered Service Agreement for Energy Use Adjustments for Network Controlled Dimmable Streetlights Limited Pilot Program.

The Settling Parties support adoption of the pilot program as proposed, without any amendment or modification. The Pilot Program agreed to by the STL Settling Parties is intended to provide a reasonable means to explore the usage reduction potential of new network control streetlight dimming devices to be demonstrated in certain local governmental jurisdictions, and to create a viable means of reflecting any related energy savings during this rate case cycle in a timely, mutually workable way that:

a. Starts to capture additional energy savings as soon as possible after dimmable lights are installed by the earliest adopter cities or counties;

b. Ensures that self-reported usage data is accurate, revenue quality data;

c. Ensures that parasitic loss from the equipment is accounted for. Other non-streetlight or parasitic load will continue to be under separate agreements in accordance with LS-2;

d. Minimizes pilot costs, through eligibility limits, standardized data transfer from loggers, and other conditions of service;

e. Works within interim work-schedule constraints on PG&E's IT/Billing System, as well as those of participating cities;

f. Drives systems standardization for these emerging technologies; and

g. Provides data and experience from early adopters that will allow all pilot participants and CAL-SLA to work with PG&E to define and evaluate the viability of longer-term approaches to dimmable streetlight rates.

The pilot program is an interim solution and, unless otherwise terminated or suspended, would continue for three years or until a final decision in Phase 2 of PG&E's 2014 GRC, whichever comes later. The pilot would include no more than five participants, with San Jose and Oakland receiving the first two reservations to participate and the remaining three spots available to another three cities or counties on a first come first served basis, with all five participants required to meet specified eligibility requirements.

Participants must have received a bid or proposal in response to a request for bids or proposals that would enable it to purchase equipment that would result in installation by December 31, 2012 of network controlled systems for at least 300 networked streetlights, and must actually install that equipment by that date. This implementation timeframe as an eligibility requirement should allow the pilot program to generate a reasonable amount of data and experience by the time parties must make proposals for PG&E's 2014 GRC Phase 2.

Each participant's control and monitoring system must include revenue grade data loggers capable of meeting relevant standards such as accuracy within +/- 2 percent consistent with Rule 17 and Direct Access Standards, and be capable of exporting usage data that meets PG&E's data requirement specifications set forth in detail in the Settlement Agreement.

Participants must notify PG&E which streetlights will be network controlled and PG&E shall set up a single separate LS-2 account with multiple service agreements to allow for a bi-monthly bill adjustment to be made on an aggregated basis. Participants are required to submit to PG&E a monthly spreadsheet report setting forth the daily energy consumed, both aggregated and by individual. PG&E will perform monthly validations of the submitted data to ensure completeness and accuracy, and will utilize validated data to create an adjustment to the standard LS-2 tariff charges to be included in the participant's bill on a bi-monthly basis. PG&E will conduct an audit during the second year of the pilot program.

Participants can opt out of the program and participation can be suspended by PG&E for various specified reasons, including exceeding maximum agreed levels of missing, inaccurate or otherwise unusable data. If the overall budget for PG&E to administer the pilot is exceeded, PG&E and the participants will reach an agreement on a cost-sharing arrangement relative to the expected administrative costs per month to participate during the remainder of the pilot.

#### 3.5.3. Discussion

As discussed further in Section 4, we find that the STL Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest. We adopt the STL Settlement Agreement without modification, and authorize PG&E to implement changes in rates in accordance with the terms of the STL Settlement Agreement.

### 3.6. Agricultural Rate Design Settlement

Multiple parties entered into an Agricultural Rate Design Settlement (Ag Settlement).[51] The Ag Settlement addresses all rate design issues for the Agricultural customer class.[52] In its original agricultural rate design PG&E testimony characterized its intent to adjust all agricultural rates to better reflect the EPMC cost-based service and cost causation, to establish revenue-neutral TOU and non-TOU rate options, and to simplify the complex array of agricultural rate schedules.

The Agricultural Settlement is contested by Lamont Public Utility District (Lamont) with respect to terms of eligibility for service under Rate Schedule 37. We resolve the dispute in Section 3.6.2 below.

---

[51] The Ag Settling Parties are AECA; CFBF; EPUC; PG&E; and the SSJID. Although CLECA; DRA, and TURN participated in the Ag settlement conferences to monitor issues that could affect revenue allocation to other classes, they do not sign the Ag Settlement Agreement. However, each has represented that it does not oppose its adoption by the Commission.

[52] The agricultural customer class covers customers served under PG&E Schedules AG-1A/B, AG-4A/B/C, AG-5A/B/C, AG-RA/B, AG-VA/B, and AG-ICE, as described in Exhibit (PG&E-14) Chapter 6. Schedule E-37 is implicitly part of the agricultural class even though Schedule E-37 customers are not agricultural customers. Rate design and rates for Schedules AG-5B and E-37 are identical and based on the combined billing determinants of Schedule AG-5B and Schedule E-37 customers.

#### 3.6.1. Uncontested Proposals in the Agricultural Rate Design Settlement

We find reasonable the following elements of the Agricultural Rate Design Settlement which were not contested by any party, and hereby adopt them.

##### 3.6.1.1. Updating of Basic Rate Design

The basic rate designs for each of the applicable Agricultural rate schedules will be updated upon implementation of the Settlement, using the methods underlying development of the illustrative settlement rates for Schedules AG-1A/B, AG-4A/B/C,AG-5A/B/C, AG-RA, AG-RB, AG-VA, AG-VB, and E-37 as presented in Exhibit A to the Settlement. These basic rate designs reflect agreement to a 1.5 percent increase to all schedule average total rates for the agricultural class.

Unless otherwise specifically agreed by the parties or addressed in the Settlement Agreement, the Settling Parties propose that the methods and explanations in Chapter 6 of Exhibit PG&E 14, served on January 7, 2011, be adopted for the purpose of implementing rates.

##### 3.6.1.2. Tariff Charges

The proposed Ag rate design reflects a 20 percent increase in customer charges for Schedules AG- A and B, and no change for Schedules AG-4C and 5C as follows:

AG-A: Current level of $14.40 increases to $17.30.

AG-B: Current level of $19.20 increases to $23.00.

AG-5B: Current level of $30.00 increases to $36.00.

Ag-4C and 5C: No change.

The Ag Settlement incorporates a 5 percent increase to Distribution and Generation Demand Charges for all Ag schedules, with a few minor exceptions as implicit in the illustrative rates presented in Exhibit A. The Ag Settlement sets unbundled Energy Charges residually, based on current Distribution and Generation seasonal and TOU relationships, as presented in Exhibit A.

The Ag Settling Parties propose to adopt the refinements to Schedule PDP rates proposed by PG&E in Chapter 6 of Exhibit (PG&E-14).

#### 3.6.1.3. TOU Revenue Neutrality:

The Ag Settlement provides for adjustment to the revenue amounts assigned to the AG-4A and AG-4B rate schedules (or other destination TOU rate schedules) over the course of the 2011 GRC cycle to account for revenue shortfalls as current AG-1A and AG-1B customers are reassigned to TOU rate schedules. These annual, after-the-fact adjustments to be made after the TOU default has occurred will measure actual revenue shortfalls from revenue neutrality and allocate shortfalls back to the destination Ag TOU schedule. It will also include a revenue credit back to the destination TOU schedule for any portion of the revenue shortfall that might be attributable to load shifting by defaulted migrating customers in response to their new TOU rates.

The revenue adjustment amount will be symmetric if there are net revenue increases rather than revenue shortfalls due to TOU migration. Similarly, the adjustments will be based on all default TOU migrating customers, and will not use only those who saved on their new TOU rate. The adjustments will track those revenue shortfalls that result strictly from structural differences between the current groups of non-TOU versus TOU agricultural rate schedules, net of any shortfalls that should be attributed to customer TOU usage shifts.

The Ag Settlement sets forth the TOU revenue-neutrality adjustment methodology, and includes illustrative revenue adjustments for AG-1A customers defaulting to AG-4A and for AG-1B customers defaulting to AG-4B. The TOU Revenue Neutrality Methodology's various features include adjustments that estimate the change in revenue due to changing load shapes when customers move to TOU. The Settlement provides that, each year in November, the Ag representatives -- as well as those of CLECA, DRA, EPUC and TURN and any other requesting parties -- will receive, review and confer with PG&E as necessary about PG&E's workpapers and analyses used to determine the revenue shortfall to be included in the final Annual Electric True-Up filing due in late December each year. In addition, the Ag Settling Parties agree to deadband ranges within which it will be assumed that the underlying Ag electricity consumption conditions are sufficiently unchanged that no further adjustments will be made to the basic TOU revenue neutrality methodology described in the Settlement.

#### 3.6.1.4. Account Aggregation

The Settlement does not adopt an agricultural aggregation tariff as proposed by AECA. Instead the Settling Parties agree to facilitate an Agricultural Settlement Account Aggregation Study (Study), to be completed by the second quarter of 2013. The Study will obtain data and other information on agricultural customers' electrical usage to allow evaluation of agricultural account aggregation. The scope, framework and methodology for the Study have been expressly agreed to by PG&E, AECA, CFBF and SSJID and are set forth in detail in Exhibit C and related Appendices 1 – 4 of the Settlement.

#### 3.6.1.5. Schedule AG-R and AG-V Enrollment Closure and Phase-Out

The Ag Settling Parties propose to immediately close both Schedule AG-R and AG-V to new enrollment. In addition, both schedules will be entirely eliminated on March 1, 2014 for customers with 12 months of interval data.

#### 3.6.2. Dispute over Proposed Expansion of Schedule E-37

The only party to protest the Ag Settlement was Lamont Public Utility District. Lamont's only disagreement with the Ag Settlement relates to the applicability of Agricultural Schedule E-37.

Lamont proposes to expand the eligibility for Schedule E-37 to include non-agricultural general water or sewage pumping customers who use 70% or more of their annual metered usage for pumping and whose annual load factor is 50% or more. Lamont describes these customers as High-load factor Non-Agricultural Pumping accounts (HiLF NAPA) (Lamont Testimony at 4). Hi LF NAPA customers pump water for residential and business consumption. Urban water agencies, such as Lamont, represent typical NAPA customers. Currently NAPA customers must take service on a General Service rate schedule. The Ag Settling Parties reject the proposal by Lamont that non-Agricultural water and sewerage pumping accounts be eligible to take service on Schedule E-37.

Lamont proposes to include an initial eligibility requirement that 70% or more of the customer's energy consumption be used for water pumping purposes, patterned after PG&E's existing agricultural applicability provision which requires that 70% of annual energy use be for agricultural end uses. Lamont incorporates the requirement "for general water or sewerage pumping" based on SCE's Pumping and Agricultural Schedule TOU-PA-5, which applies to all types of pumping (Agricultural Pumping, Oil Pumping and NAPAs). (Lamont's Op. Test., at 4).

Lamont claims that NAPA customers with high load factors, such as urban water agencies, have lower costs of service than general service customers and should be eligible for lower pumping rates on Schedule E-37 instead of general service commercial and industrial rate schedules. Lamont claims that NAPA customers have costs of service comparable to customers taking service under Schedule E-37. Thus, Lamont proposes that HiLF NAPAs be made eligible for Rate Schedule E-37 based on the lower rates currently found in Schedule E-37. Lamont also would agree to the lower rates found in Schedule AG-5B, as offering comparably lower rates.

PG&E disputes Lamont's claims as to the costs to serve urban/business water pumping accounts relative to the general service schedules and E-37 and AG-5B.

PG&E submitted testimony in opposition to Lamont and in support of the Ag settlement on August 26, 2011. The Agricultural Settling Parties claim (1) that E-37 may no longer be suitable for its original purpose (much less expanding participation absent further study), (2) the cost shifts to other customers from the revenue shortfall as non-agricultural pumping customers migrate away from commercial/industrial rate schedules to E-37, and (3) the absence of a current cost of service study for both E-37 customers and the non-agricultural pumping customers.

The Ag Settling Parties agree as a compromise to support the following steps:

(a) immediately close E-37 to new enrollment,

(b) provide a one-way customer option for existing E-37's to migrate to A-10, A-10-TOU, or E-19/20,

(c) require PG&E to study a new cost-based E-37 industrial schedule allocation for oil and non-Ag water pumping accounts to be filed in the 2014 GRC Phase 2, and

(d) consider in the 2014 GRC Phase 2 proceeding whether E-37 should be eliminated and whether a new cost-based pumping rate, including

> large non-Ag pumping, should be offered, as an optional rate to the otherwise applicable tariff.

PG&E contends that enabling non-agricultural pumping customers to switch between classes would run contrary to the Commission practice and policy of using broad customer class definitions for ratemaking. PG&E supports the Agricultural Settlement provision, deferring consideration of Lamont's proposal to the 2014 GRC proceeding, when a complete marginal cost analysis can be performed on all distribution, generation and transmission costs.

Lamont wants urban/business customers to get rates on a schedule based on agricultural costs of service. NAPA urban/business customers are spread throughout PG&E's service territory, often in heavily populated urban rather than rural areas. As a result, PG&E claims that their cost of service is higher than for low-cost rural distribution planning areas.

PG&E presented Marginal Distribution Capacity Costs (MDCC) differentiated across its 18 operating divisions in Appendix A to the April 8, 2011 MLLP Rate Design Supplemental Settlement Agreement. Some MDCC accounts are high. The MCAC for Schedule E-19 are well above those for the agricultural class figures in those operating divisions likely to have heavy concentrations of water agenies.

Lamont's proposal applies to existing urban/business customers who would be able to migrate from general service rate schedules to the lower E-37 rate. This migration will produce revenue shortfalls that will impact other customers. Lamont calculated a revenue shortfall from the migration of urban/business pumping customers to E-37 of approximately $18.4 million. (Lamont Comments, page 5.)

PG&E witness Coyne also points out that an additional $25.5 million revenue shortfall could occur if high and low load factor nonagricultural water pumping customers were eligible. (Coyne, Ex. 159, at 28, lines 26 to 29; at 29, Table 4, line 7; at 30, lines 4 to 7.) Lamont's proposal would cause customers in all classes to bear the shortfalls through normal balancing account amortizations. (*Id.* page 29, lines 5 to 6.)

PG&E estimates a revenue shortfall resulting from Lamont's proposal of $12.3 million ($16.4 million if A-1 and A-6 accounts are included). This estimate is less than Lamont's "high-end" estimate of up to $18.4 million.

PG&E argues that the fact that water pumping for agricultural purposes may count as one of the agricultural activities towards meeting the 70% requirement, however, does not turn PG&E's agricultural schedules into tariffs for pumping end-uses. PG&E's agricultural tariffs remain limited to agricultural customers.

Lamont's proposal would permit the migration of a substantial number of customers onto a rate schedule that has not been designed to reflect the billing determinants or cost of service of the new migrants.[53] PG&E argues that there will be an adverse dollar impact on other ratepayers since NAPA customers will not migrate to E-37 unless their bills will be lower. PG&E argues that there is no indication that Lamont's proposal will cause inactive accounts to return to service, contrary to the purpose for which E-37 was approved, i.e., returning shut-in wells to the system.

---

53 Coyne, Ex. 159, at 32, lines 5 to 8.

Lamont did not present a marginal cost study, but offered three statistics (time of use TOU shares, load factors, summer on-peak demand to summer maximum demand) to support its claim that HiLF NAPA customers have a lower marginal cost justifying eligbility for Schedule E-37.

Lamont claims that NAPAs have a TOU profile similar to those customers currently on Schedule E-37. Because NAPAs tend to operate around the clock, they utilize a relatively higher proportion of off-peak energy as compared with General Service accounts that operate only during the Monday through Friday from 9 am to 5 pm.

PG&E claims these statistics are selective, incomplete, and inconclusive. PG&E and other sponsors of the Agricultural Settlement argue that an actual cost of service study for NAPA customers is needed before determining if these customers should receive a reduced rate like E-37.

#### 3.6.2.1. Discussion

We find that the Ag Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest as discussed in Section 4 below. We adopt the Ag Settlement Agreement without modification, and authorize PG&E to implement changes in rates in accordance with the terms of the Ag Settlement Agreement.

We find that Lamont's proposal to expand the eligibility of Schedule E-37 to include HiLF NAPA customers is not justified. Likewise, Lamont's secondary proposal to allow HiLF NAPA customers to qualify for some other rate schedule with comparable rates to E-37 has not been justified. In order to enable HiLF customers to be eligible for lower utility rates if Lamont's proposal were to be adopted, other customers would be burdened with higher rates necessary to make up the shortfall. Lamont has not provided a showing to support the shifting of that cost burden to other customers. The Ag Settlement provides a reasonable approach to addressing the concerns regarding rate levels paid by HiLF NAPA customers raised by Lamont.

In 1997 when Schedule E-37 was established, oil prices were low and many California oil wells were shut-in. Schedule E-37 was established to provide incentives to oil pumping accounts to return idle oil wells to production when California crude oil prices were low. Schedule E-37 was exclusively for customers engaged in crude petroleum and natural gas extraction in D.97-09-047 in PG&E's 1997 Rate Design Window proceeding. D.97-09-047 explicitly recognized California Senate Bill 2007 as a legislative impetus to reactivate idle oil wells in approving Schedules E-36 and E-37 as incentive rates.[54]

This legislation provided relief for a 10-year period from state production charges for wells that had become inactive. That 10-year period ended in 2006. Because of these changed circumstances, the rate assumptions underlying Schedule E-37 may no longer be relevant, and existing rates for existing E-37 customers warrant reexamination. Thus the Agricultural Settlement is reasonable in proposing to close the E-37 rate to new and returning oil pumping customers, while the 2014 GRC 2 case reviews the reasons for E-37 and the marginal cost for both E-37 and pumping customers. Given these factors, Lamont's proposal to allow new categories of customers to take service on Schedule E-37 is not well timed. Now is not the time to expand eligibility of Schedule E-37 to new categories of customers, particularly for end-uses that were never intended by the Commission in establishing Schedule E-37.

---

[54] E-36 was subsequently consolidated with E-37 for rate simplification purposes in D.05-11-005, in PG&E's 2003 GRC Phase 2 proceeding.

Lamont argues that HiLF NAPAs should be subject to lower rates based on their marginal costs of service. Although Lamont presented limited data on costs of service, there is no actual cost of service study in the record applicable to HiLF NAPAs. Lamont's comparison metrics for different customer types are anecdotal, and are not an acceptable substitute for a marginal cost study.

Even if a true cost of service study were to establish similar marginal costs of service for nonagricultural water pumpers, Lamont's E-37 proposal disregards customer classes and instead would use a marginal cost grouping for rate design. Rate design is based on broad customer classes or subclasses that generally reflect average costs of service for each class, with rates set accordingly. (Coyne, Ex. 159, at 12, lines 2 to 4.) Within a customer class, individual customers' load may exhibit higher or lower marginal costs due to a variety of factors.

Lamont's proposal would allow non-agricultural pumping customers to switch to a rate schedule that is combined with large agricultural customers. PG&E's agricultural tariffs are suited to agricultural customers, with a variety of agricultural activities eligible to establish the agricultural nature of the customer. The Commission adopts rate design and revenue allocation based on broad class definitions. PG&E's tariffs maintain stability among rate group definitions in a mutually exclusive manner and do not allow customers to migrate between customer classes (absent specific legislative or Commission direction.)

Lamont explains that it does not seek to have HiLF NAPAs classified as agricultural or oil pumping customers, but merely recommends implementing lower rates for those customers by copying the rate that is labeled "agricultural" (AG-5B) or "oil pumping" (E-37). Lamont argues that NAPA customers' cost of service is comparable to that of Schedule E-37. Lamont does not claim that NAPAs qualify as "oil pumpers" under E-37's applicability provision, or that

NAPAs face the same economic concerns that prompted creation of Schedule E-37 in 1997.

Despite Lamont's disclaimers, the practical effect of Lamont's proposal would be to treat HiLF NAPAs as if they were agricultural customers. Lamont fails to justify why non-agricultural pumping customers, such as HiLF NAPAs, belong on Schedule E-37 that is designed exclusively for agricultural customers.

NAPAs eligibility for a pumping rate must be tied to the inherent nature of the customer, in terms of the basic residential, commercial, industrial, agricultural, standby, streetlight, or other customer types – not to the nature of the end-use. (PG&E Resp. Test., pg. 7, A10).

At present, the rates for Schedules AG-5B and E-37 are identical and are based on the merged billing determinants and cost of service determinations of both populations. The billing determinants of HiLF NAPAs are not reflected in those two rates, however. Lamont's proposal would thus impose significant subsidies on other customers.[55]

Deferring Lamont's proposal to the 2014 GRC 2 will provide an opportunity to develop an adequate record regarding an actual cost study of both oil pumping customers and non-agricultural pumping customers, and to devote more careful consideration to the rate impacts of merging the billing determinants and costs of service of different groups of customers.

Lamont claims that the cost characteristics of HiLF NAPAs are not like those of other customers taking service under the General Service rate schedule and therefore should be offered the E-37 rate option. Lamont claims that Hi LF

[55] Coyne, Ex. 159, at 32, lines 8 to 13.

NAPAs (1) have higher annual load factors composed to General Service accounts and oil pumping accounts, (2) have greater off-peak usage, (3) have peak demands that are less coincident with the system peak, and (4) have predictable and consistent usage and provide reliable and low-risk revenue from year to year.

Lamont seeks to compare HiLF NAPAs with all E-37 customers, not just those E-37 customers with a load factor greater than 50%. Limiting the comparison to customers with a load factor greater than 50%, however, provides a more consistent starting point from which to contrast other relevant metrics.

PG&E observes, that when E-37 customers with a load factor greater than 50% are compared to HiLF NAPAs, the average E-37 customer is over five times larger in terms of kWh, over five times larger in terms of maximum kW, and over six percentage points better in average LF. Based on these comparisons, E-37 customers may have a significantly lower cost of service per kWh than NAPA customers. (PG&E Resp. Test., at 27-28, A27).

The "cost of service" used in rate design and revenue allocation is not an absolute dollar amount, but is stated as a cost per kWh or other unit of consumption. PG&E witness Gideon takes the information developed by PG&E witness Troup and converts it to a kWh basis in Exhibit 101, Appendix A, Full Cost Rates (full cost of service).

Lamont presents comparisons of average usage per customer by TOU period to support its claim that HiLF NAPA customers show greater similarities to oil pumping customers than to General Service customers. Lamont, however, presents no data as to the relative level of activities in summer versus winter for oil pumping customers or non-agricultural water pumpers. Without this data, the comparisons as to average usage by TOU period are inconclusive. Also, TOU periods are too broad to evaluate customers' peak loads, whether non-coincident or coincident with the system peak. Hourly load data is needed. Lamont provided no hourly load data for non-agricultural pumping loads (or any other customer loads) (Coyne, Ex. 159, at 28, lines 5 to 7.)

Lamont also compares average annual load factor per account for high and low load factor non-agricultural pumping versus agricultural load, oil pumping, and general service. Annual average load factor percentages, however, do not provide the information needed to evaluate marginal costs to serve different customer groups. (Gideon, Ex. 101, at 2- 8, lines 7 to 9 and at 2-9, lines 5 to 7 and lines 29 to 31.)

PG&E presented information on the different marginal distribution capacity costs (MDCC) by division, along with the number of E-37 customers and high load factor non-agricultural pumping customers in each division. (Coyne, Ex. 159, table 1 and figure 1, at 23 and 24.). E-37 customers are concentrated in the third and fourth operating divisions with the lowest MDCC. Non-agricultural water pumping customers, however, are spread throughout all of PG&E's operating divisions where MDCCs are higher. Since non-agricultural pumping accounts have a higher weighted average MDCC than oil pumping accounts, high load factor non-agricultural pumping customers are unlikely to have an overall average cost of service comparable to that of oil pumping accounts. (*Id.* page 26, lines 8 to 9.)

PG&E provided the weighted average MDCC for the non-agricultural water pumping customers, commercial, agricultural and the AG-5B agricultural/oil pumping group. (Troup, Ex. 163) That data showed that the non-agricultural MDCCs for high load factor and other water pumpers are higher than the MDCCs for commercial, agricultural or the AG-5B agricultural/oil pumping groups on a general system basis. Exhibit 163 conflicts with that Lamont's broad assertions about MDCCs. An actual cost of service study is therefore needed to test Lamont's claims.

## 4. Review of Settlements

With the exception of the limited disputes raised by certain parties as noted above, all of the active parties who submitted testimony on the issues in this proceeding joined in support of the respective Settlement Agreements. As a matter of public policy, the Commission favors settlement of disputes if they are fair and reasonable in light of the record. This policy supports worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.[56]

The rules for the submission and review of settlements are set forth in Article 12 of the Commission's Rules of Practice and Procedures. The general criteria for Commission approval of settlements are stated in Rule 12.1(d) of the Rules of Practice and Procedure.[57] Rule 12.1(d) provides that "[t]he Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest." The Commission has rejected (or provided for modification of) settlements when these criteria are not met.

We find that the Settlements are reasonable in light of the whole record. The outcomes constitute a compromise between the positions set forth in the

---

[56] D.92-12-019, 46 CPUC2d 538, 553.

[57] Unless otherwise indicated, subsequent rule references are to the Rules of Practice and Procedure.

prepared testimony by PG&E and the positions of parties that were active on this issue.

We conclude that the parties have appropriately complied with the applicable procedural rules governing notice and submission of the settlements presented in this proceeding. To qualify as an all-party settlement, the sponsoring parties must show that that a settlement meets the following four conditions:

1. The settlement agreement commands the unanimous sponsorship of all active parties to the proceeding;
2. The sponsoring parties are fairly reflective of the affected interests;
3. No term of the settlement contravenes statutory provisions or prior Commission decisions; and
4. The settlement conveys to the Commission sufficient information to permit it to discharge its future regulatory obligations with respect to the parties and their interests.

In assessing settlements, we consider individual settlement provisions but, in light of strong public policy favoring settlements, we do not base our conclusion on whether any single provision is necessarily the optimal result. Rather, we determine whether the settlement as a whole produces a just and reasonable outcome

Factors to be considered in reviewing settlements include: (1) the risk, expense, complexity and likely duration of further litigation, (2) whether the settlement negotiations were at arms-length, (3) whether major issues were addressed, and (4) whether the parties were adequately represented.[58] The

[58] Re Pacific Gas & Electric Company, 30 CPUC2d 189, 222.

Commission must be assured that parties to a settlement were able to make informed choices in the settlement process. With respect to whether a settlement agreement is consistent with the law, the Commission must be assured that no term of the settlement agreement contravenes statutory provisions or prior Commission decisions. A settlement that implements or promotes state and Commission policy goals embodied in statutes or Commission decisions would be consistent with the law. To determine whether a settlement agreement is in the public interest, in addition to substantive public interest concerns associated with the circumstances of a particular proceeding, the Commission may inquire into whether a settlement expeditiously resolves issues that otherwise would have been litigated.

In this instance, the parties convened and provided timely notice of a settlement conference (Rule 12.1(b)). They filed motions for approval of each of the settlements, each of which provided a statement of the factual and legal considerations adequate to advise the Commission of the scope of the settlement and of the grounds on which adoption is urged (Rule 12.1(a)).

> The Commission will not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

In the following sections we discuss the merits of the Settling Parties' proposal as it relates to our approval criteria.

While participation in each of the settlements varied depending on parties' specific interests, a review of the signatories to each of the settlements indicates that the sponsoring parties are fairly reflective of the affected interests. Sponsors of each settlement fairly represent the wide variety of types of customers and customer classes that are affected by the issues addressed therein. The settlements are reasonable compromises of Settling Parties' respective litigation positions. The settlements avoid the cost of further litigation, and conserve scarce resources of parties and the Commission.

The terms of each settlement agreement are also consistent with law. The record contains the prepared testimony of all the parties on marginal cost and revenue allocation, The Settlement Agreement contains detailed descriptions regarding the timing of rate changes and the manner in which they are to be implemented.

Finally, based on the record that contains the testimonies of all parties and the settlement provisions regarding the timing of rate changes and the manner of implementing rate changes between GRCs, we determine that the settlements convey sufficient information to permit the Commission to discharge future regulatory obligations.

Our long-standing policy is that contested settlements should be subject to more scrutiny compared to an all-party settlement.[59] We explained the rationale behind this heightened scrutiny in D.07-03-044:

> In judging the reasonableness of a proposed settlement, we have sometimes inclined to find reasonable a settlement that has the unanimous support of all active parties in the proceeding. In contrast, a contested settlement is not entitled to any greater weight or deference merely by virtue of its label as a settlement; it is merely the joint position of the sponsoring parties, and its reasonableness must be thoroughly demonstrated by the record. (D.07-03-044, at 13 (quoting D.02-01-041, at 13).)

---

[59] D.07-03-044, Opinion Authorizing PG&E's GRC Revenue Requirement for 2007-2010, mimeo., at 13 (citing D.96-01-011, Finding of Fact 5).

We have expressed a willingness to consider, and when appropriate, approve settlements that are not joined by all parties. In D.10-12-035 (the QF Summit Decision), the Commission stated that, for many years, it has been willing to consider a settlement not supported by all parties under the following criteria "[W]e consider whether the Settlement taken as a whole is in the public interest. In doing so, we consider the individual elements of the settlement in order to determine whether the settlement generally balances the various interests at stake as well as to assure that each element is consistent with our policy objectives and the law." (QF Summit Decision, mimeo, at 27, citations omitted.)

To the extent that certain settlement issues were contested in this proceeding, we provided opposing parties the opportunity to be heard through evidentiary hearings. Based on the results of those hearings, as discussed in detail above, we have concluded that the terms of the settlements offer reasonable results.

Consistent with Rule 12.1(d), we thus find that each of the settlements presented above are reasonable in light of the whole record, consistent with law, and in the public interest. Also, the Settling Parties have followed and met the settlement proposal requirements of Rules 12.1(a) and 12.1(b).

## 5. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with § 311 of the Public Utility Code and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. Comments were filed on ____, and reply comments were filed on ____ by ____.

## 6. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Thomas R. Pulsifer is the assigned ALJ.

## Findings of Fact

1. PG&E entered into a series of settlements, covering the scope of Phase 2 issues as set forth in the appendices of this decision. Each of the settlements had support among all active parties relating to each referenced subject area, except for certain objections relating to solar rate incentives, and agricultural pumping rates.

2. Although the Master Meter Schedule ET discount was not resolved by settlement, the only parties submitting responsive testimony to PG&E's proposed Schedule ET discount were The Utility Reform Network and WMA.

3. Evidentiary hearings were held to address and resolve disputed issues relating to the Schedule ET Discount for master meter MHP customers.

4. California's strong public policy is to favor settlements, thereby supporting many worthwhile goals, such as reducing litigation expense, conserving scarce resources, and reducing parties' risk that litigation will produce unacceptable results.

5. The Commission considers individual settlement provisions but, in light of California's strong public policy in favor of settlements, does not base its conclusion primarily on whether any single provision is the necessarily optimal result but rather on whether the settlement as a whole produces a just and reasonable outcome.

6. Except for the limited protests noted below, each of the Settlements are sponsored by all active parties participating in each respective subject area, including residential, small commercial, large commercial, agricultural and

industrial customers. As such each of the settlements is fairly reflective of the affected interests.

7. The Settlements, along with the full evidentiary record, contain sufficient information for the Commission to discharge its future regulatory duties with respect to adopted matters.

8. The settlements submitted on marginal cost and revenue allocation, streetlight rate designed, and SLP rate design are uncontested all-party settlements.

9. The relative percentage increases and decreases in average electric rates for customer classes as set forth in Appendix A of this decision, under the column entitled "Settlement", represents the applicable changes that result from the Settlement Agreement on Revenue Allocation and Marginal Cost. The revenue allocation percentages shown in Appendix G result from the adopted settlement agreements.

10. The MLLP settlement is supported by all active parties, with the exception of elements contested by certain parties regarding the treatment of (a) customer eligibility for the Schedule A-6 Solar Pilot and (b) the Option R rate schedule allowing reduced demand charges for solar customers.

11. The MLLP settlement is reasonable in light of the whole record, after taking into consideration disposition of the contested issues raised by Solar Alliance to expand the A-6 Solar Pilot and to introduce an Option R rate.

12. Under the existing Schedule A-6 Solar Pilot, customers otherwise required to take service under Schedule E-19 (i.e., customers with ordinary demands above 500 kW) are allowed to take service on Schedule A-6 if they serve at least 20 % of their maximum demand with solar DG.

13. The proposal to increase the eligibility for the A-6 Solar Pilot by raising the cap on participation from 20 MW to 50 MW would result in increased subsidies, and would increase the degree of cost shifting to non-participating customers.

14. The E-19 and E-20 schedules include time-differentiated demand charges in on-peak and partial peak periods for both generation and distribution costs. All distribution costs, except those paid in a fixed customer charge, are capacity-related, and cannot be avoided by reducing energy consumption during a peak hour.

15. Capacity-related costs occur at the distribution, transmission and generation levels of the electric grid.

16. Because generation, transmission and primary distribution infrastructure serve many customers, an individual customer's contribution to these capacity costs depends on the customer's contribution to the coincident peak at the corresponding level of aggregation.

17. For the portion of the distribution system that is closest to the customer, the capacity required to serve the customer is driven by the customer's non-coincident peak demand. Because the distribution capacity costs for infrastructure near the customer are a function of the customer's maximum demand, non-coincident demand charges are an appropriate mechanism for collecting the revenues needed to cover these costs.

18. Because an individual customer's peak load may not coincide with system peak loads, demand charges, even peak-period demand charges, to collect revenues for generation, transmission and primary distribution capacity costs only approximate customers' contributions to system peaks.

19. Customers' average demands during peak hours may better reflect their contribution to upstream capacity costs. Thus, the use of TOU energy charges to

spread these costs over all peak hours during a billing period may yield more accurately capacity charges for upstream capacity costs rather than instantaneous peak-period and non-coincident maximum demand charges, particularly for customers with erratic loads, such as customers with behind-the-meter solar generation facilities.

20. The demand charge rate structure proposed in the MLLP settlement is consistent with long-established rate design principles for large customers

21. Solar Alliance's proposed rate options to expand the A-6 Pilot and to introduce an Option R rate are designed to reduce or eliminate the use of demand charges, and instead collect larger portions of costs in more readily avoidable energy (per kWh) charges. An additional number of customers with very large electric loads would receive service under a tariff originally designed to meet the needs of much smaller commercial customers (i.e., with demands of 20-50 kW.

22. Shifting demand charges to TOU energy rates increases the rate at which net energy metered customers are compensated for net exports during discrete TOU periods. To the extent higher compensation rates for net energy metering exports may overcompensate customer-generators for their solar energy, an increased cross-subsidy from noncustomer-generators may occur.

23. It is not clear whether Public Utilities Code Section 2827(h)(2)(B) would allow an electric utility to offer an optional rate for customer-generators that would compensate customer-generators at a lower rate during a discrete TOU period than they would otherwise pay for energy consumed during that TOU period.

24. Under the Electric MHP Service ET rate schedule, electricity is delivered to a single master meter and then delivered to end users at individual mobile homes through a sub metered private distribution system

25. The ET discount compensates the master metered MHP owner for those costs that the utility avoids because the master metered MHP owner has submetered all the tenants' spaces rather than have the utility directly serve them.

26. In calculating the ET discount, PG&E proposed escalation factors to adjust its new connection equipment costs from 2003 to 2011 dollars using labor (O&M) escalation specific to PG&E. All parties agreed with this approach.

27. All parties agree to use ML&P (Schedule A-10) connection costs at secondary voltage as a reasonable proxy for the MHP master meter connection costs.

28. The quantified effect on the ET discount is small, with PG&E's proposed after-tax RECC adjustment lowering its recalculated ET discount by less than a penny per space per day (all else equal) relative to TURN's previously proposed pre-tax RECC adjustment.

29. The addition of an EPMC scalar in calculating the Schedule ET discount would artificially inflate the discount by overstating utility avoided costs, and would contravene established Commission precedent.

30. The inclusion of connection costs above the utility line extension allowance in the Schedule ET discount would contravene D.04-04-043 Attachment A.

31. WMA's proposal to add explicit replacement costs in the Schedule ET discount would causes double counting.

32. The use of residential class average equipment costs to calculate the Schedule ET discount would produce inflated results because it is predominantly

based on single family units which have higher costs of service than do both multifamily and MHPs costs.

33. The agricultural rate design settlement was contested only with respect to the opposing proposal of Lamont Public Utility District in seeking to expand the applicability of Schedule E-37 to include non-agricultural pumping customers.

34. Although Lamont presented limited cost data comparisons, there is no actual cost of service study in the record applicable to high-load factor non-agricultural pumping account customers. Lamont's comparison metrics are anecdotal, and are not an acceptable substitute for a marginal cost of service study.

35. A cost of service study would be necessary as an initial step to determine the cost to serve the high-load factor non-agricultural pumping account customers in addition to the current E-37 rate class.

36. Without a cost of service study, Lamont's proposal for expanded eligibility for the E-37 rate schedule could lead to significant cost shifts to other groups of customers without cost-based justification.

37. The Commission adopts revenue allocation based on broad customer classes or subclasses that generally reflect average costs of service for each class, with rates set accordingly.

38. As a basis for assessing the merits of expanding the Schedule E-37 eligibility, all of the factors affecting the cost basis of rates are relevant, not just the load factor. Other key factors include size of customers, location of customers, voltage levels of customers, and summer/winter splits of usage.

39. There is no evidence that the load shapes of high load factor non-agricultural pumping account customers or their seasonal usage is similar to those of current E-37 customers. There is no evidence comparing their

contributions to system peak or maximum demand to those of all current E-37 customers.

40. Although customers with more usage during the winter compared to the summer are less expensive to serve on a cost per kWh basis, the customers Lamont proposes to add to the schedule are served at lower voltages.

41. PG&E's tariffs maintain stability among rate group definitions in a mutually exclusive manner and do not allow customers to migrate between customer classes (absent specific legislative or Commission direction.)

42. Schedule AG-5B and E-37 rates currently are identical and based on the merged billing determinants and cost of service determination of both.

43. The 2014 GRC will provide an opportunity to develop an adequate record regarding a cost of service study of both oil pumping customers and non-agricultural pumping customers, and to devote more careful consideration to the rate impacts of merging the billing determinants and costs of service of different groups of customers.

44. The settlement agreements on marginal cost and revenue allocation, streetlight rate design, SLP rate design, MLLP rate design, and agricultural rate design settlement agreements are each reasonable in light of the record, consistent with law and in the public interest.

## Conclusions of Law

1. The Commission will not approve a settlement unless it is reasonable in light of the whole record, consistent with law, and in the public interest.

2. The Commission will not approve an all-party settlement unless the settlement commands the unanimous sponsorship of all active parties, sponsoring parties are fairly reflective of the affected interests, no settlement term contravenes statutory provisions or prior Commission decisions, and the

settlement conveys sufficient information to permit the Commission to discharge future regulatory obligations with respect to parties and their interests.

3. The all-party settlements submitted in this proceeding, covering revenue allocation and marginal cost, SLP rate design, streetlight rate design, and Schedule ES and Natural Gas Baseline Quantities satisfy the Commission's criteria for reasonableness and should be approved. Each of the pending motions to approve these settlements should be granted.

4. Although the MLLP rate design settlement was contested by certain parties with respect to proposals to expand eligibility for the A-6 Solar Pilot and introduce an Option R provision, the settlement was otherwise supported by all active parties in all other respects, and nonetheless is reasonable in light of the whole record and warrants approval and adoption. The motion to approve the MLLP rate design settlement should be granted.

5. The proposal to expand eligibility for the A-6 Solar Pilot and introduce an Option R provision should be denied. Instead, the proposals in the MLLP Settlement Agreement pertaining to the A-6 Solar Pilot and Option R should be adopted.

6. Prior to filing its next GRC Phase 2 application, PG&E should complete a cost study on the extent to which the demand charges in the E-19 and E-20 tariffs penalize customers with erratic loads by overcharging them for their contributions to systems peaks. This cost study should evaluate:

(a) whether an Option R rate for E-19 and E-20 customers that shifts some portion of generation and distribution demand charges to TOU energy charges may more appropriately recover capacity-related costs from customers with on-site solar generation facilities;

(b) the correlation of solar output and solar customer-generator loads at various levels of geographic aggregation and how the correlation, or lack of correlation, affects their contribution to capacity costs;

(c) the additional compensation that may accrue to customer-generators as a result of higher TOU energy rates under net energy metering; whether the higher compensation results in an additional subsidy for customer-generators; and

(d) the feasibility of designing optional rates that offer different rates for energy consumption and net energy production during discrete TOU periods.

7. Although the Agricultural Rate Design Settlement was contested with respect to the proposal to expand the eligibility of Schedule E-37 to include certain non-agricultural pumping customers, the settlement was otherwise supported by all active parties in all other respects, and nonetheless is reasonable in light of the whole record and should be approved and adopted. The motion to approve the Agricultural Rate Design Settlement should be granted.

8. The proposal of the Lamont Public Utility District to expand eligibility for Schedule E-37 to include non-agricultural general water or sewage pumping customers whose annual metered usage is 70% or more for and whose annual load factor is 50% or more should be denied. Lamont describes these customers as High-load factor Non-Agricultural Pumping accounts.

9. The proposal of the Lamont Public Utility District to permit high-load factor non-agricultural pumping accounts to migrate from the existing applicable General Service tariff to some other rate schedule with rates comparable to E-37 should be denied.

10. The proposals in the Agricultural Settlement with respect to Schedule E-37 are reasonable and should be adopted without change.

11. The proposed Schedule ET master meter discount of $6.53 per master meter MHP space per month, $1.02 Line Loss Adder, and the illustrative

Diversity Benefit Adjustment of $5.15, all proposed by PG&E and supported by TURN, are reasonable and should be adopted for purposes of this proceeding.

12. PG&E's illustrative Diversity Benefit Adjustment of $5.15 should be adopted subject to recalculation after the adoption of this decision.

13. PG&E's proposed weighted after-tax cost of debt Real Economic Carrying Charge adjustment should be used for the limited purpose of setting the ET discount in this proceeding, without setting a precedent for purposes of any other proceedings.

14. WMA's claim that the Commission must decide whether connection costs above the utility line extension allowance are in or out of the submeter discount, as this would contravene D.04-04- 043 Attachment A.

15. In order to provide a more informed basis for future determinations of master meter discounts, Pacific Gas and Electric should be required to collect information on the actual costs of serving mobile home park customers and present this data in its next Phase 2 GRC proceeding.

16. This order should be made effective immediately so that PG&E may prepare the necessary advice letter, and so that rates may be timely adjusted

## O R D E R

**IT IS ORDERED** that:

1. The motions, filed by Pacific Gas and Electric Company, and which request adoption of each of the settlement agreements, as referenced below respectively, are each hereby granted. Each of the settlement agreements attached to the motions respectively, are identified below:

| Date of Motion | Scope of Settlement Agreement |
|---|---|
| a. March 14, 2011 | Marginal Cost and Revenue Allocation |
| b. April 8, 2011 | Medium and Large Light and Power (MLLP) Rate Design |
| c. April 8, 2011 (As amended September 22, 2011) | Small Light and Power (SLP Rate Design |
| d. June 3, 2011 | Streetlighting Rate Design |
| e. June 22, 2011 | Schedule ES and Natural Gas Baseline Quantities |
| f. July 18, 2011 | Agricultural Rate Design |

2. The terms of each of the settlement agreements as referenced in Ordering Paragraph 1, and as reproduced in Appendices A, B, C, D, E and F of this decision, respectively, are hereby approved and adopted without change.

3. Pacific Gas and Electric Company is directed to file tariffs within 15 days of the date this decision is mailed, in compliance with General Order 96-B, to implement the revenue allocations and rate design changes for the respective customer classes identified in the adopted settlement agreements in accordance with the terms and conditions as set forth in Appendices A, B, C, D, E and F, and as adopted herein.

4. Pacific Gas and Electric Company's revised tariff sheets to implement the revenue allocations and rate designs adopted in this order shall become effective on or after January 1, 2012, subject to Energy Division determining that they are in compliance with this order. No additional customer notice need be provided pursuant to General Rule 4.2 of General Order 96-B for this advice letter filing.

5. The rules governing the existing revenue requirement categories presented in the March 14, 2011, Settlement Agreement are adopted for use in this proceeding only, and shall not govern or be precedential for purposes of Pacific Gas and Electric Company's 2014 General Rate Case.

6. Pacific Gas and Electric Company shall schedule and conduct workshops, providing notice to parties in this proceeding prior to filing its 2014 general rate case Phase 2 application. The workshops shall be a forum to discuss the data and/or methodologies that might be used in that proceeding, and potential model simplification and transparency, for: (a) the marginal generation cost data that might be used to develop marginal costs; (b) the marginal distribution capacity costs and marginal customer access cost data to develop marginal costs; and (c) revenue allocation methodologies that might be used to develop positions in the 2014 general rate case Phase 2.

7. The proposal of The Solar Alliance is requesting to expand the eligibility of the Schedule A-6 Pilot from the existing cap of 20 megawatt (MW) to 50 MW denied.

8. The proposal of The Solar Alliance requesting to implement an Option R under Schedules E-10 and E-20 to replace the otherwise-applicable generation capacity-based time-of-use (TOU) demand charges with energy charges, and replace 50 percent of the standard non-TOU distribution-related maximum demand charges with non-TOU energy charges is denied.

9. Prior to filing its next General Rate Case Phase 2 application, Pacific Gas and Electric Company shall complete a cost study on the extent to which the demand charges in the E-19 and E-20 tariffs penalize customers with erratic loads by overcharging them for their contributions to systems peaks. The cost study shall include the following analysis:

a. Evaluation of whether an Option R rate for E-19 and E-20 customers that shifts some portion of generation and distribution demand charges to time-of-use energy charges may more appropriately recover capacity-related costs from customers with on-site solar generation facilities.

b. Assessment of data on the correlation of solar output and solar customer-generator loads at various levels of geographic aggregation and how the correlation, or lack of correlation, affects their contribution to capacity costs.

c. Estimation of the additional compensation that may accrue to customer-generators as a result of higher time-of-use energy rates under net energy metering,

d. Discussion of whether the higher rates of net energy metering compensation result in additional subsidy for customer-generators, and discussion of the feasibility of designing optional rates that offer different rates for energy consumption and net energy production during discrete time-of-use periods.

10. The proposal of Lamont Public Utility District is to expand the eligibility of Agricultural Rate Schedule E-37 (or another comparable rate schedule) to include non-agricultural general water or sewage pumping customers whose annual metered usage is 70% or more for and whose annual load factor is 50% or more, described as High-load factor Non-Agricultural Pumping accounts hereby denied.

11. The Pacific Gas and Electric Company's proposal for the Schedule ET avoided cost-based base discount of $6.53 per master meter mobile home park space per month is hereby adopted.

12. Pacific Gas and Electric Company's proposed $1.02 Line Loss Adder is adopted.

13. Pacific Gas and Electric Company's illustrative Diversity Benefit Adjustment of $5.15 is approved, subject to recalculation after the adoption of this decision.

14. Pacific Gas and Electric Company's proposed escalation factors applicable to ET discount cost inputs are hereby adopted.

15. Pacific Gas and Electric Company's proposed transformer costs, at secondary voltage, for calculating the Mobile Home Park master meter connections are hereby adopted.

16. Pacific Gas and Electric Company's weighted after-tax cost of debt Real Economic Carrying Charge adjustment is adopted for the sole purpose of setting the ET discount in this proceeding, without setting a precedent for purposes of other proceedings,

17. Pacific Gas and Electric Company's adjustments to Account 903 costs are adopted, which exclude from the Schedule ET discount specific ongoing utility costs in Account 903 that are still incurred despite Pacific Gas and Electric Company not having to directly serve each Mobile Home Park tenant.

18. Pacific Gas and Electric Company's proposed Minimum Average Rate Limiter is adopted.

19. Pacific Gas and Electric Company and The Utility Reform Network's proposed use of marginal customer access Costs is hereby approved to develop the Schedule ET discount using the Commission-approved rental cost method.

20. Pacific Gas and Electric Company and The Utility Reform Network's proposed use of 2003 General Rate Case access equipment cost data, escalated to 2011, is hereby approved for Schedule ET rate design.

21. Pacific Gas and Electric Company and The Utility Reform Network's proposed use of multifamily service line connection costs is hereby approved for Schedule ET discount calculations.

22. Pacific Gas and Electric Company's transformer costs, at secondary voltage, for Mobile Home Park master meter connections are adopted for purposes of the Schedule ET discount calculations.

23. Prior to its filing its next General Rate Case Phase 2 application, Pacific Gas and Electric Company shall collect data and complete a study on the actual costs to serve mobile home park customers as a basis to better determine the costs that the utility would have incurred in providing comparable services directly to the users of the service.

24. This proceeding remains open to consider Phase III issues as previously identified by the Assigned Commissioners' Scoping Memo.

25. Application 10-03-014 remains open.

This order is effective today.

Dated ____________________________, at San Francisco, California.