Decision **PROPOSED DECISION OF ALJ MATTSON** (Mailed 9/30/2005)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 04-06-024 (Filed June 17, 2004)

(See Appendix A for a list of appearances.)

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INTERIM OPINION ADOPTING SETTLEMENT WITH FIVE SUPPLEMENTAL SETTLEMENTS ON MARGINAL COST, REVENUE ALLOCATION, AND RATE DESIGN

1. Summary

The purpose of this proceeding is to establish just and reasonable electric rates for Pacific Gas and Electric Company (PG&E or applicant) effective January 1, 2006. These rates allow applicant to collect the revenue requirement determined in Phase 1 of applicant's test year 2003 general rate case (GRC), as modified by subsequent revenue requirement decisions. This is accomplished by assessing applicant's marginal costs, allocating revenues to customer classes, and designing rates.

To achieve these goals, applicant and parties have submitted a range of evidence, engaged in settlement discussions, and filed motions for Commission adoption of a settlement regarding marginal cost, revenue allocation and rate design, plus five supplemental settlements on rate design. We find that these settlements meet our tests for adoption, and grant the motions. All issues but one are now resolved. The proceeding remains open solely to address the issue of the agricultural class definition.

2. Background

2.1. Application and Proposed Testimony

On November 8, 2002, PG&E filed its formal application for a test year 2003 GRC. The GRC encompassed Phase 1 to address revenue requirement issues, and Phase 2 to address rate design issues. On May 27, 2004, the Commission issued its decision on Phase 1 issues, and directed applicant to file a separate rate design application. (Decision (D.) 04-05-055.)

On June 17, 2004, applicant filed this application and supporting proposed testimony. On August 20, 2004, the first prehearing conference (PHC) was held. On August 27, 2004, the Scoping Memo and Ruling of the Assigned Commissioner was issued. The Scoping Memo, among other things, determined that the category for this proceeding is ratesetting, stated the issues, and set the schedule.

Consistent with the schedule (as amended by subsequent rulings), applicant served supplemental and updates of proposed testimony, proposed rebuttal testimony, plus errata and corrections during the period from December 2004 through May 2005. Five Public Participation Hearings were held in January and February 2005. The Office of Ratepayer Advocates (ORA) and other parties served proposed testimony and rebuttal testimony during the period from January through April 2005.

2.2. BART and SierraPine Issues

In May 2005, the San Francisco Bay Area Rapid Transit District (BART) and SierraPine Ltd. (SierraPine) asked that a limited issue specific to each be decided on an expedited schedule. Their request was granted. On July 21, 2005, we found that neither BART nor SierraPine are subject to certain charges associated with applicant's energy recovery bonds (ERBs).[1] (D.05-07-041.)

2.3. Settlements

On February 17, 2005, applicant served notice on all parties of a settlement conference. (Rule 51.1(b) of the Commission's Rules of Practice and Procedure

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[1] The ERBs are authorized and used to reduce ratepayer costs related to applicant's bankruptcy reorganization. (See D.04-11-015.)

(Rules).) On March 9, 2005, PG&E hosted the initial settlement conference. Additional settlement discussions were held in subsequent weeks by conference call.

On May 13, 2005, applicant and settling parties filed a motion asking the Commission to adopt a settlement (May 13, 2005 Settlement) resolving issues on marginal cost, revenue allocation, and limited rate design matters. The May 13, 2005 Settlement is in Attachment B.

On June 3, 2005, applicant and settling parties filed a motion for Commission adoption of two supplemental settlements: Supplemental Residential Settlement and Supplemental Small Light and Power Settlement. These two Settlements are in Attachments C and D, respectively.

On July 8, 2005, applicant and settling parties filed a motion for Commission adoption of three supplemental settlements: Supplemental Light and Power Settlement, Supplemental Agricultural Settlement, and Supplemental Energy Recovery Bond Settlement. These three Settlements are in Attachments E, F and G, respectively.

Hearings were held on May 23, June 3, June 9 and July 12, 2005, to receive evidence and hear testimony from panels on various Settlements. The Settlements resolve all outstanding issues regarding marginal costs, revenue allocation and rate design, except one. Settling Parties assert that each settlement is reasonable in light of the whole record, consistent with law and in the public interest, and should be adopted. We address the Settlements in this decision. The one remaining issue involves the definition of the agricultural class. We will address that issue in a subsequent decision.

3. Terms of Settlements

3.1. May 13, 2005 Settlement

The 16 parties joining in the May 13, 2005 settlement include all the active parties. The May 13, 2005 Settlement resolves marginal cost, revenue allocation and some rate design issues.

In summary, the major points of the May 13, 2005 Settlement provide that:

a. Marginal Cost: Settling Parties agree not to address electric marginal costs in this proceeding. Rather, Settling Parties generally agree that the residential customer class is bearing less than its full cost of service while most non-residential customer classes are bearing more than their cost of service. To better align rates with costs, Settling Parties agree on revenue allocation, and that no further assessment of marginal cost is needed here.

b. Revenue Allocation: Settling Parties agree to specific revenue allocations, or allocation methodologies.

    1. Five revenue changes before January 1, 2006: Two revenue increases, and one decrease, are allocated to all classes on a system average percentage basis consistent with the allocation guidance set forth in the Rate Design Settlement Agreement (RDSA). (D.04-02-062, Paragraph 10 of the RDSA.) This essentially changes the revenues for each customer class by the same percentage on a function by function basis. Two decreases will be allocated entirely to the non-residential classes consistent with the RDSA method on a component by component basis.

    2. A.04-06-024 Rate Changes on January 1, 2006: Electric revenues are reallocated on a revenue neutral basis using agreed upon sales forecasts, generally resulting in a slight increase for residential customers, and decreases for other customers. Also, $2.97 million is moved from generation to the nuclear decommissioning component of rates, slightly reducing revenue collected from bundled customers and increasing the revenue from Direct Access (DA) customers, consistent with the Phase 1 decision. (D.04-05-055, Attachment A, page 12.)

The table below shows the average electric rates for each customer class as of March 1, 2005. It also shows the approximate average electric rates that would be expected January 1, 2006 by application of the RDSA (without the changes agreed to in the May 13 Settlement), and those expected to result from the May 13, 2005 Settlement. These rates are for the 5 revenue requirement changes before January 1, 2006 and the revenue neutral allocation January 1, 2006. Finally, it shows the percent changes.

TABLE 1

CURRENT, RDSA AND SETTLEMENT AVERAGE RATES

CLASS	CURENT RATE (March 1, 2005) (cents per kWh) A	RDSA RATE (January 1, 2006) [1] (cents per kWh) b	SETTLEMENT RATE (January 1, 2006) (cents per kWh) c	PERCENT CHANGE (RDSA from current) d = b/a	PERCENT CHANGE (Settlement from RDSA) e = c/b	PERCENT CHANGE (Settlement from Current) f = c/a
BUNDLED						
Residential	12.802	12.500	13.067	-2.4%	4.5%	2.1%
Small L&P	15.042	14.588	13.858	-3.0%	-5.0%	-7.9%
Med L&P	14.277	13.563	12.575	-5.0%	-7.3%	-11.9%
E-19	12.855	12.190	11.342	-5.2%	-7.0%	-11.8%
Street Lights	15.129	14.988	14.399	-0.9%	-3.9%	-4.8%
Standby	13.636	13.086	12.402	-4.0%	-5.2%	-9.0%
Agricultural	11.917	11.676	11.275	-2.0%	-3.4%	-5.4%
E-20	10.652	9.995	9.279	-6.2%	-7.2%	-12.9%
Total	12.990	12.512	12.300	-3.7%	-1.7%	-5.3%
DIRECT ACCESS						
Residential	8.418	8.480	8.484	0.7%	0.1%	0.8%
Small L&P	8.351	8.530	8.534	2.1%	0.0%	2.2%
Med L&P	6.535	6.673	6.664	2.1%	-0.1%	2.0%
E-19	6.068	6.191	6.190	2.0%	0.0%	2.0%
Agriculture	6.235	6.362	6.365	2.0%	0.1%	2.1%
E-20	3.924	3.957	3.984	0.8%	0.7%	1.5%
Total	4.833	4.901	4.915	1.4%	0.3%	1.7%

[1] Absent the revenue allocation in the May 13 Settlement, Settling Parties assume all revenue changes would be allocated based on the method in the RDSA, and result in the rates estimated herein.

L&P is Light and Power.

3. Other Changes on January 1, 2006: Revenue requirement changes for 11 specifically identified proceedings are categorized into three functional groups (generation-related, non-generation-related, fixed transition amount (FTA)-related), and the allocation treatment is specified. The ratemaking applies only to these 11 proceedings. Settling Parties make no assumptions about the direction or size of these 11 revenue requirement changes. In general, revenue increases will be allocated to all groups (with increases to residential classes potentially offset by some FTA-related decreases). All other decreases will be allocated only to non-residential groups. Settling Parties also agree to an approach should the revenue changes be delayed until after January 1, 2006.

4. Other Revenue Requirement Changes: Settling Parties agree that allocation of revenue changes other than those explicitly listed, and specifically for those after January 1, 2006 and before the effective date of the rate design decision in PG&E's next GRC, will be governed by the RDSA, not the specific revenue allocations stated in this May 13, 2005 Settlement, or as otherwise ordered by the Commission.

5. Other Revenue Allocation Issues: Any remaining allocation issues are deferred to Phase 2 of PG&E's 2007 GRC.

c. Rate Design

1. Direct Access Cost Responsibility Surcharge (DA CRS): Settling Parties agree that non-core bundled customers have funded more than their share of the DA CRS undercollection, and agree to certain rate adjustments until the Commission looks at DA CRS funding in R.02-01-011 or as the Commission may otherwise direct.

2. Nonfirm Program Incentives: The incentive for nonfirm service shall be retained at the level now in effect until the Commission determines otherwise in PG&E's next GRC or elsewhere (e.g., A.05-01-016, et al. Critical Peak Pricing proceeding).

3. Phase 2 of Baseline Rulemaking: Shortfalls from programs adopted in Phase 2 of the Baseline Rulemaking (D.04-02-057) will be recovered from the residential class by function based on the RDSA method.

4. Residential Generation Revenue Memorandum Account (RGRMA): Tier 3 and 4 rate levels resulting from Resolution E-3906 were reasonable and require no adjustment. The RGRMA can be eliminated.

5. Electric Master Meter Discount: The master-meter discount for Schedule ET- Mobilehome Park Service is increased from $0.343 to $0.379 per space per day until the next GRC Phase 2 proceeding. The master-meter discount for Schedule ES-Multifamily Service remains the same at $0.10579 per unit per day.

6. Streetlight Non-Energy Charges: Changes will be effective March 1, 2006 (rather than January 1, 2006), various elements are set (e.g., hookup costs, non-conforming load requirement conditions, meter charges, photocontrol standards, revenue requirement for non-energy charges), and tables adopted for revenue requirement, allocation and rates. Exhibit 47 contains the street light class tariffs related to the May 13, 2005 Settlement to which parties agree.

3.2. Supplemental Residential Settlement

The 3 parties joining in the Supplemental Residential Settlement are all the active parties on residential issues. Rates are to be designed as set forth in the supplemental settlement, and illustrative rates are the starting point for determining rate changes on January 1, 2006 necessary to collect the adopted revenue requirement. In summary, the major points of the Supplemental Residential Settlement provide that:

a. California Alternate Rates for Energy (CARE): CARE rates will remain unchanged. The current calculation of CARE rates shall be retained.

b. Baseline: Target baseline quantities in PG&E exhibits are to be adopted. Applicant shall file advice letters in 2006 to phase-in the new quantities on April 1, 2006 (gas) and May 1, 2006 (electric), subject to existing 5 percent single-family and 10 percent multifamily baseline quantity phase-in bill increase limitations for electric service.

c. Tier 3, 4 and 5 Surcharges: Prior to a decision in applicant's 2007 GRC Phase 2, rates for usage in excess of 130 percent of baseline for non-CARE customers shall be determined by setting the Tier 3, 4 and 5 surcharges the same on all applicable non-CARE residential rate schedules.

d. Medical Baseline: Effective May 1, 2006, medical baseline rates remain unchanged for usage below 130 percent of baseline, but a new Tier 3 rate equal to the non-CARE Tier 3 rate shall apply to all usage in excess of 130 percent of baseline. Medical baseline customers will be eligible to apply for the Family Electric Rate Assistance (FERA) program.

e. Time of Use (TOU): Existing TOU rates are closed, and new revenue-neutral TOU rates are opened, on May 1, 2006.

f. Installation Charges: Certain installation charges are eliminated May 1, 2006, and two existing TOU meter charges shall continue at their current level.

g. Rate Differential by Tier: Total rates shall be designed such that the rate differential by tier shall be made up of both generation and distribution within each tier in the same proportion as total distribution to generation revenues allocated to schedule.

h. Employee Discount: The current employee discount shall apply the 25 percent discount to the full Tier 1 rate, plus 25 percent of the full Tier 2 rate for all usage over baseline.

i. Illustrative Rates: Rates are shown which collect the revenue allocated in Table 2 of the May 13, 2005 Settlement. Adopted revenue requirements shall be applied to these initial rates.

3.3. Supplemental Small Light and Power Settlement

The 4 parties joining in the Supplemental Small Light and Power Settlement are all the active parties on these issues. Rates are to be designed as set forth in the supplemental settlement, and illustrative rates are the starting point for determining rate changes on January 1, 2006 necessary to collect the adopted revenue requirement. In summary, the major points of the Supplemental Small Light and Power Settlement provide that:

a. Customer Charges: Customer charges for Schedules A-1 and A-6 are increased to $8.10 and $12.00 per month for single phase and poly phase service, respectively. Customer charges for Schedules A-15 and TC-1 remain at current levels. The facilities charge for Schedule A-15 shall be increased to $15.00 per month.

b. TOU Charges: Effective May 1, 2006, Schedule A-6 TOU processing and installation charges are eliminated, and ongoing meter charges remain at current levels.

c. Commercial CARE: The calculation of commercial CARE bills shall remain unchanged and rely on a 20 percent discount based on the methodology specified in Schedule E-CARE.

d. Energy Rates for Schedule A-15: The energy rates for the unbundled public purpose program, distribution and generation rate components of Schedule A-15 will be set equal to those calculated for Schedule A-1.

e. Schedule E-36: Effective May 1, 2006, Schedule E-36 shall be discontinued and existing customers transferred to Schedule A-1 or another applicable schedule.

f. Illustrative Rates: Rates are shown which collect the revenue allocated in Table 2 of the May 13, 2005 Settlement. Adopted revenue requirements shall be applied to these initial rates.

3.4. Supplemental Light and Power Settlement

The 9 parties joining in the Supplemental Light and Power Settlement are all the active parties on these issues. Rates are to be designed as set forth in the supplemental settlement, and illustrative rates are the starting point for determining rate changes on January 1, 2006 necessary to collect the adopted revenue requirement. In summary, the major points of the Supplemental Light and Power Settlement provide that:

a. <u>Methods</u>: Basic rate designs will be updated using methods proposed by PG&E in Exhibit 11, with limited exceptions to mitigate changes from existing relationships under Schedules E-19 and E-20.

b. <u>15-Minute Demand Charge Interval</u>: Effective May 1, 2006, demand charge intervals are changed from 30 minutes to 15 minutes for service under Schedules E-19, E-20, A-10 (over 400 kW demand) and E-19V (over 400 kW demand).

c. <u>Customer Charges</u>: PG&E's proposed customer charges are adopted.

d. <u>Rate Limiters</u>: Summer season on-peak rate limiters for Schedules E-19 and E-20 are eliminated. Summer season average rate limiters continue to be applicable for customers on Schedules E-19 and E-20 taking service at distribution voltages.

e. <u>Optimal Billing Program</u>: Effective May 1, 2006, the Optimal Billing Program is eliminated. (This program allowed certain food processing customers on Schedules E-19 and E-20 to re-designate certain meter read dates at the beginning and end of their peak processing seasons.)

f. <u>Discontinue Schedule E-25</u>: Effective May 1, 2006, Schedule E-25 is eliminated. (This is a short-peak-period TOU rate option for less than 10 qualifying water agency customers otherwise eligible for Schedules E-19 or E-20.)

g. Power Factor Adjustments: Effective May 1, 2006, power factor adjustment rates are converted on a revenue neutral basis from a percentage of billed revenues basis to a per kilowatt-hour (kWh) basis.

h. TOU Meter Charges: Effective May 1, 2006, TOU installation and processing charges are eliminated for customers with demand less than 500 kW electing to take voluntary TOU service under Schedule E-19.

i. Energy Efficiency Clause on Schedule E-20: The Energy Efficiency Adjustment clause is eliminated from Schedule E-20 (established over 15 years ago to maintain eligibility for service under Schedule E-20 for a limited number of customers who would otherwise be served on Schedule E-19).

j. Updated Standby Service Rates: PG&E's proposed methods for setting standby rates are reasonable. Further consideration is deferred to Phase 2 of PG&E's 2007 GRC of the issue regarding distribution-voltage standby rates that might fully allocate distribution capacity costs to Schedule S on the same basis as if no customer generation were installed.

k. New Physical Assurance Contract: Effective May 1, 2006, PG&E's proposed standard form contract for Physical Assurance is adopted with respect to distributed generation customers taking service under Schedule S.

l. Eliminate Non-Firm Rate Option Under Schedule S: The new Physical Assurance Agreement may be used as a substitute for establishing separate non-firm service rates for standby customers.[2]

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[2] Settling Parties state that no customer would be affected by eliminating the existing provisions for non-firm standby service because no Schedule S customer has ever elected this service option.

m. Ratchet for Standby Contract Demand: Effective May 1, 2006, the standard ratchet period is reduced from 36 months to 12 months for standby service reservation capacity elected under Schedule S.

n. Standard Non-Firm Service Rates: PG&E will restate the existing non-firm program terms and conditions and corresponding rate credits in the form of a separate, supplementary rate schedule. The supplementary schedule will then apply as a rider to otherwise applicable charges under Schedules E-19 or E-20.

o. Non-Firm Rate Eligibility: Non -firm tariff eligibility is restored for a small number of customers who previously took non-firm service but who lost their eligibility due to a change in corporate ownership.

p. Schedule E-BIP: Schedule E-BIP is modified to include an Underfrequency Relay (UFR) service option comparable to that under PG&E's standard non-firm tariffs. Participants electing the UFR program agree to make their load available for complete and automatic interruption in the event of certain system disturbances and receive an additional incentive of $8.00 per kW per year.

q. Account Aggregation Proposals Deferred: Further consideration of account aggregation proposals for agricultural and water agency pumping load is deferred to Phase 2 of PG&E's 2007 GRC.

r. Illustrative Rates: Rates are shown which collect the revenue allocated in Table 2 of the May 13, 2005 Settlement. Adopted revenue requirements shall be applied to these initial rates.

3.5. Supplemental Agricultural Settlement

The 4 parties in the Supplemental Agricultural Settlement are all the active parties on these issues. Rates are to be designed as set forth in the supplement settlement, and illustrative rates are the starting point for determining rate changes on January 1, 2006 necessary to collect the adopted revenue requirement. In summary, the major points of the Supplemental Agricultural Settlement provide that:

a. Agricultural Applicability: The agricultural applicability definition (i.e., agricultural class definition) will be addressed separately, and parties will seek a separate decision by January 2006. Parties agree the definition does not affect the development or implementation of rates January 1, 2006.

b. Rate Consolidation: Current agricultural rate schedules shall be retained and PG&E's proposed rate consolidation will be dropped. Effective May 1, 2006, Schedule AG-7 shall be eliminated and customers given rate analyses to assist in selecting another rate schedule.

c. Ratcheted Demand Charges: Ratcheted demand charges shall be discontinued (including both the demand charge rate limiter and drought relief option tied to ratcheted demand charges). Balance of contract and minimum demand provisions shall be eliminated.

d. Schedules AG-4C and AG-5C: Shall be redesigned to replace the current off-peak ratcheted maximum demand charges with a standard maximum demand charge. By May 1, 2006, voltage discounts shall be made available.

e. TOU Meter Charges: Effective May 1, 2006, TOU meter installation and processing charges are eliminated. The two current daily TOU meter charges are retained, with the lower daily charge applicable only to customers who paid the installation charge prior to its elimination.

f. DAP and GAP Options: Effective May 1, 2006, the current Diesel Alternative Power (DAP) and Natural Gas Alternative Power (GAP) options are discontinued.

g. Account Aggregation: Further consideration of agricultural and water agency pumping load account aggregation proposals is deferred to Phase 2 of PG&E's 2007 GRC. PG&E will provide staff and other resources for a study mutually agreed to between PG&E, Agricultural

Energy Consumers Association (AECA), California Farm Bureau Federation (CFBF) and East Bay Municipal Utility District (EBMUD).

h. Data: PG&E will make specified data available to AECA and CFBF at the time PG&E files Phase 2 of its 2007 GRC.

i. Changes: Except as specified herein, revenue allocation and rate design shall use equal percentage change methods established in the RDSA. Rates for oil pumping Schedule E-37 shall be set equal to the rates in Schedule AG-5B.

j. Illustrative Rates: Rates are shown which collect the revenue allocated in Table 2 of the May 13, 2005 Settlement. Adopted revenue requirements shall be applied to these initial rates.

3.6. Supplemental Energy Recovery Bond Settlement

The 2 parties to the Supplemental Energy Recovery Bond Settlement are the active parties on this issue. In summary, Settling Parties agree that while the cap for departing load customer should include the ERB, in the unlikely event that ERB cannot be collected under the cap, rates will be adjusted to ensure that the ERB is fully collected from the responsible customers.

More specifically, Settling Parties agree that, to the extent the Commission determines that the $0.027 per kWh cap on the Cost Responsibility Surcharge (CRS) is appropriate for any Departing Load (DL) customers, and if the full amount of the energy recovery bond charges are recoverable under the cap, the capped amount shall include recovery of the following components in the following order: (1) Department of Water Resources (DWR) Bond Charge, (2) Energy Cost Recovery Amount (the amount of ERB charges specified in Ordering Paragraph 65 of D.04-11-015), (3) Ongoing Competitive Transition Charges (CTC), and (4) DWR Power Charges. In the remote event that the ERB charges cannot be recovered from all responsible customers under the $0.027 per kWh CRS cap, rates will be adjusted such that the ERB charge is fully recovered from all responsible customers on a timely basis without deferral. Any shortfall that results will be attributed only to the CRS component that is not fully recovered. The shortfalls resulting from the capping will then be recovered only from those DL customers who are required to pay the particular CRS component that was not fully recovered due to the cap. As a result, customers not required to pay ERB charges will not be required to pay ERB shortfalls. Only non-exempt capped customers are responsible for their respective shortfalls.

4. Discussion

4.1. Standards of Review

We have reviewed settlements as far back as at least 1988.[3] In doing so, we have often acknowledged California's strong public policy favoring settlements. This policy supports many worthwhile goals, such as reducing litigation expenses, conserving scarce resources of parties and the Commission, and allowing parties to reduce the risk that litigation will produce unacceptable results.

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 the optimal result. Rather, we determine whether the settlement as a whole produces a just and reasonable outcome.

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[3] See, for example, D.88-12-083 (30 CPUC2d 189), D.90-08-068 (37 CPUC2d 346), D.92-12-019 (46 CPUC2d, 538), D.93-04-056 (49 CPUC2d 72), D.93-12-016 (52 CPUC2d 317), D.96-01-011 (64 CPUC2d 241), D.98-04-064 (80 CPUC2d 1), D.03-12-035, D.04-02-062, D.04-05-055, D.05-03-022, D.05-06-016, and D.05-06-032.

We have specific rules regarding approval of settlements:

> "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." (Rule 51.1(e).)

In addition, Settling Parties offer the May 13 Settlement as an all-party settlement. As first articulated in 1992, we condition our approval of an all-party settlement on the following factors:

a. The settlement agreement commands the unanimous sponsorship of all active parties;

b. Sponsoring parties are fairly reflective of the affected interests;

c. No settlement term contravenes statutory provisions or prior Commission decisions; and

d. The settlement conveys sufficient information to permit the Commission to discharge future regulatory obligations with respect to parties and their interests.[4]

Settling Parties argue here that the May 13 Settlement meets the all-party tests. Further, they contend that the May 13 Settlement plus the 5 Supplemental Settlements meet the broader tests of being reasonable in light of the whole record, consistent with law, and in the public interest. We agree as explained below.

4.2. May 13 Settlement

[4] D.92-12-019 (64 CPUC 2d 538, 550-551).

Settling Parties assert that the May 13 Settlement meets all four all-party settlement tests. We agree. First, Settling Parties are all the active parties on the issues that are the subject of the May 13 Settlement.

Second, Settling Parties include residential, small commercial, large commercial, agricultural and industrial customers. These parties are fairly reflective of the affected interests.

Third, no term of the settlement contravenes statutory provisions or prior Commission decisions. This is examined further below.

Lastly, the record contains the direct and rebuttal testimonies of all parties. The May 13 Settlement, in combination with the record, contains sufficient information to permit the Commission to discharge its future regulatory obligations with respect to the parties and their interests.

4.3. May 13 Settlement plus the 5 Supplemental Settlements

Settling Parties contend that the May 13 Settlement plus the 5 Supplemental Settlements meet the tests of being reasonable in light of the whole record, consistent with law, and in the public interest. No party recommends rejection of any settlement. We conclude the settlements meet our tests for approval, and merit adoption.

4.3.1. Reasonable in Light of the Whole Record

The record consists of over 80 exhibits, plus testimony at evidentiary hearing over two days from panels of expert witnesses in support of individual settlements. The Administrative Law Judge (ALJ) asked specific questions of Settling Parties, answered both in writing and by panelists. The record is thorough and supports the settlements.

Regarding marginal costs, Settling Parties argue that the primary purpose of determining marginal costs in this proceeding is to establish the cost of service for revenue allocation to customer class. Settling Parties disagree on particular marginal costs and the magnitude of revenue changes needed to bring customer classes to their full cost of service. Nonetheless, Settling Parties state they generally agree that the residential class is bearing less than its full cost of service, and most non-residential classes are bearing more than their full cost of service. With this general concurrence regarding costs, Settling Parties agree to a revenue allocation that brings electric rates into better alignment with PG&E's costs of service to each customer class while at the same time tempering the magnitude and abruptness of changes to any one customer class. They do so without agreeing to particular marginal costs, and recommend that none be adopted here.

In support, Settling Parties assert that, since the GRC revenue allocation is revenue neutral, the larger the increase to residential customers the larger the decrease to all other customers. Parties disagree on the cost of service, the magnitude of the revenue changes needed to align revenues with full cost of service, and the merits of various measures used to mitigate the adverse effects of large increases. The following table, however, shows the spectrum of Settling Parties' litigation positions on the cost of service, revenue allocation after recommended mitigation, and the settlement result for the residential class:

TABLE 2

POSITIONS ON RESIDENTIAL CLASS AVERAGE BUNDLED RATE INCREASE

PARTY	FULL COST OF SERVICE	RESULT AFTER MITIGATION
TURN	6.5%	2.5%
ORA	5.3%	3.0%
PG&E	15.3%	11.9%

CMTA/ICP	16.0%	16.0% [2]
SETTLEMENT	Unknown [1]	About 4.5% [3]

[1] Parties do not agree on specific marginal costs, and thus the full cost of service resulting from the settlement is unknown.

[2] No mitigation is recommended.

[3] Parties state it may be greater than 4.5%, but only to a limited degree and over a period of time (e.g., 11 other revenue changes to take effect on January 1, 2006, and others to take effect before the decision in Phase 2 of PG&E's 2007 GRC).

We agree that Settling Parties' proposal is reasonable in light of the whole record. Even without determining specific marginal costs, the record shows that charging full cost by any party's measure means increases to the residential class, with offsetting decreases to other classes. Parties agree, however, on a revenue allocation that moves rates closer to cost while mitigating adverse effects.[5] The approximate 4.5% increase is below even the smallest "full cost" increase, and thereby "moves rates substantially in the direction of full cost of service without (in all likelihood) overshooting the mark by anyone's measure." (May 13, 2005 Motion to Adopt Settlement, page 3.) The approximate 4.5% increase is squarely in the mid-range of the outcomes recommended in the parties' litigation positions. These outcomes are reasonable in light of the whole record.

Particular rate design outcomes are also reasonable in light of the whole record, often reflecting the position of one or another party, or a compromise between PG&E and parties active on particular issues and rate schedules. For example, PG&E sought an increase in CARE customer rates and ORA proposed no increase for low-income residential CARE customers. The settlement provides for no increase. Similarly, PG&E sought increases in customer charges for Schedules A-1 and A-6 while NRDC and ORA both recommended no increase. The settlement provides for a moderate increase.

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[5] Settling Parties state that among the ways this is accomplished is "by linking mitigation of the residential rate level resulting from this proceeding to the peak level of residential electric rates during the recent energy crisis." (May 13, 2005 Motion to Adopt Settlement, pages 1-2.) More specifically, "…rates resulting from the Phase 2 allocation as set forth in Table 2 of the [May 13] Settlement Agreement…already set residential rates for purposes of this proceeding at the energy crisis level, less $26 million (the estimated residential class share of the second series of the energy recovery bonds)." (Exhibit 48, Answer 5.3 at page 9.)

All parties had the opportunity to review the results of other settlements for impacts on their interests, and no party objects to any settlement. For example, Setting Parties state that settlements on master meter discounts and streetlight non-energy charges were negotiated only by the few parties active on these issues, but all parties had the opportunity to review the results for impacts on their interests and no party raises an objection. This is similarly true for residential, small light and power and all other settlements.

4.3.2. Consistent with Law

Settling Parties assert that the May 13 Settlement with the 5 Supplemental Settlements comply with all laws and Commission decisions. We agree.

For example, Settling Parties point out that the Commission's currently adopted revenue allocation principles for incremental revenue changes after February 2004 apply only "prior to the adoption of rates in Phase 2 of PG&E's 2003 GRC [i.e., this proceeding]…" (D.04-02-062, Attachment A, Paragraph 10.) Thus, this decision governs revenue allocation and rate design for all matters addressed herein (e.g., various specified rate changes before,[6] on, and after January 1, 2006).

Further, Settling Parties state that the Settlements are consistent with Water Code § 80110 (adopted as part of Assembly Bill 1X in January 2001) by

[6] If the May 13, 2005 Settlement is rejected, parties recognize that allocation of revenue changes before January 1, 2006 will revert back to principles adopted in the RDSA. In fact, the May 13, 2005 Settlement states parties' understanding of this treatment. For example, parties state that the DWR allocation effective June 1, 2005 will be adjusted to RDSA principles reflected in AL 2647-E-A, rather than the allocation in the May 13, 2005 Settlement actually implemented via AL 2647-E-B, if the May 13, 2005 Settlement is rejected. (May 13, 2005 Settlement at § V.3.a, pp. 10-13; also see Resolution E-3933 adopted May 26, 2005.)

providing that revenue requirement changes within the residential class are allocated entirely to usage in excess of 130 percent of baseline. Settling Parties assert that the ERB Settlement continues methods prescribed in D.03-07-028 and D.04-02-062, in a manner consistent with the requirements of Senate Bill 772 and the Public Utilities Code. Settling Parties point out that changes to baseline quantities in the Settlement Agreement are consistent with Public Utilities Code § 739 (regarding baseline),[7] and D.05-06-029 (regarding gas seasonal redefinition, moving April from winter to summer). The Settlement is consistent §§ 739.1 and 739.2 (regarding CARE), § 739.5 (regarding residential master meter submetering), and § 739.7 (regarding an appropriate residential inverted tier rate structure). PG&E and Settling Parties state in response to several questions that the resulting rates are just, reasonable, and nondiscriminatory, in compliance with §§ 451 and 453.

No party provides any contradictory information. We conclude the Settlements are consistent with law.

4.3.3. In the Public Interest

Settling Parties assert the May 13 Settlement with 5 Supplemental Settlements is in the public interest. We agree.

The settlements are a reasonable compromise of Settling Parties' respective litigation positions. The settlements avoid the cost of further litigation, and conserve scarce resources of parties and the Commission. The settled revenue allocation moderates potentially harsh bill impacts while better aligning rates with costs. PG&E will soon make a marginal cost showing in Phase 2 of its 2007

[7] All statutory references are to the Public Utilities Code unless stated otherwise.

GRC.[8] Parties will there have a full opportunity to litigate calculation of specific marginal costs, for which a decision is not needed and not reached here.

The Settling Parties' recommended overall residential class increase is reasonable. Absent the May 13, 2005 Settlement, rates on January 1, 2006 would be allocated via the RDSA, and the residential class average bundled rate would decrease by 2.4%. (See Table 1 above.) This would be inconsistent with moving rates to cost. Even with its own proposed mitigation, applicant sought an overall 11.9% increase in the residential class average bundled rate compared to rates at March 1, 2005 levels. (Exhibit 11, Attachment 2, page 3.) The May 13, 2005 Settlement, however, results in only a 2.1% increase from rates at March 1, 2005 levels. (Table 1 above.) This moves rates toward costs but substantially moderates adverse effects.

While we would like to further moderate the increase to residential customers, all parties agree that residential customers are paying less than their cost and some increase is reasonable. There is no testimony to the contrary. Parties representing residential customers assert they made reasonable tradeoffs of a moderate overall revenue increase with mitigation measures (e.g., not exceeding any party's estimate of full cost, retaining the total at less than energy crisis levels) plus favorable individual rate elements (e.g., no increase for CARE, no Tier 4 for medical baseline). We think the Settling Parties' judgment is

[8] That showing is due about March 1, 2006. (See letter dated September 1, 2005, from Commission Executive Director Steve Larson to PG&E granting PG&E a Rule 48(b) request to defer its marginal cost showing from Phase 1 to Phase 2 of its 2007 GRC; proceeding number TEND 1205.)

consistent with the public interest, and we will not disturb their compromise result.

We would also like to further reduce commercial, industrial and other rates. Parties representing those customers accept a more moderate decrease. We will not second guess the results satisfactorily and voluntarily reached by all Settling Parties.

We also note that individual rate elements are consistent with the public interest. For example, Settling Parties agree to reinstate residential Tier 5. This provides a powerful conservation incentive for the largest residential users, assists with satisfying other Settlement parameters, and is in the public interest.

Similarly, demand and energy charges for light and power customers were disputed. EBMUD sought lower levels of maximum demand charges and higher levels of TOU energy charges, thereby providing greater incentives for usage management to avoid these charges. PG&E recommended charges based on its marginal costs. Most other parties favored higher maximum demand charges and lower TOU energy rates. The Settlement represents a compromise that sets the maximum demand charge half way between what would have been determined based on the RDSA method and the level recommended by PG&E. This is a balance that minimizes bill impacts while still adjusting total rates and TOU rate differentials to apply updated and more accurate cost-based prices. The result will motivate load-shifting, energy efficiency and conservation, and is in the public interest.

In furtherance of the public interest, we implement this order by requiring applicant to provide the following additional notice. The Supplemental Light and Power Settlement provides for eliminating Schedule E-25 effective May 1, 2006. The bill impact analysis shows that two accounts currently on Schedule

E-25 are subject to reduced bills if they move to Schedule E-19. (Exhibit 55.) Customers on Schedule E-25 need sufficient notice of their rate options prior to closure of this schedule in order to make reasonable decisions. To provide this opportunity, PG&E should serve written notice on all Schedule E-25 customers no later than 90 days prior to May 1, 2006. The notice should inform them of the closure of this schedule along with their rate options. Consistent with the provisions for closing Schedule AG-7 contained in the Supplemental Agricultural Settlement, the notice should include rate analyses to assist Schedule E-25 customers select the best alternative rate schedule.

4.4. Conclusion

The May 13, 2005 Settlement is an all-party settlement and meets our tests for adoption. The May 13, 2005 Settlement plus the 5 Supplemental Settlements, taken as a whole, are reasonable in light of the whole record, consistent with law, and in the public interest. The Settlements produce just and reasonable results and merit our adoption.

5. Comments on Settlements

No party opposes any Settlement. The California Clean DG Coalition (CCDC), however, filed comments on both the May 13, 2005 Settlement and the Supplemental Light and Power Settlement.

CCDC seeks Commission coordination of distributed generation (DG) issues in these settlements with DG tariff matters before the Commission in the DG Order Instituting Rulemaking (R.04-03-017). Specifically, CCDC requests that the Commission either modify the Settlements, or include an ordering paragraph in this decision, providing that the eligibility period for standby charge exemptions authorized by statute (§ 353 et seq.) and extended by the Commission (D.03-04-060) remain in effect until the Commission issues a decision regarding establishment of DG rates in R.04-03-017 (or any other proceeding where DG tariffs are considered), and such rates become effective, notwithstanding any approved standby rates in this proceeding (A.04-06-024).

Applicant responded in opposition to modifying the settlements. We agree. The relief CCDC seeks is a Commission affirmation of exemptions authorized by statute and extended by the Commission. Such language more appropriately comes from the Commission than via a modified settlement.

Applicant does not oppose an ordering paragraph similar to that recommended by CCDC, but suggests rewording to better identify matters in various proceedings. CCDC proposes refined language in its comments on the Supplemental Light and Power Settlement that is compatible with PG&E's. We adopt the ordering paragraph largely as worded by PG&E to reflect the matters before us.

PG&E argues that we might decline to include the ordering paragraph since it is outside the scope of this proceeding. To the contrary, rate design in general is before us in this proceeding, and standby rates are specifically addressed. (For example, see Attachment E, § V.12.) We think the assurance sought by CCDC is not unreasonable.

6. Residential Nonrefundable Discount Percentage for New Customer Connections

On March 7, 2005, TURN moved to ensure inclusion of an issue in this proceeding. The issue is whether or not the Commission should eliminate the nonrefundable discount option for new customer connections.[9] The motion was unopposed, and was granted. The ruling was reversed on appeal, however, since elimination of the option would change applicant's revenue requirement, and changes in revenue requirement are outside the scope here. (See Rulings dated March 15, 2005 and March 30, 2005.)

Nonetheless, PG&E is obligated to periodically review the factors used to determine the residential allowance, non-refundable discount option percentage rate, and cost-of-service factor related to line extensions. PG&E must file an advice letter if its review shows a change of more than 5% is warranted. (PG&E Electric Tariff Rule 15.I.2.[10]) PG&E states that it is planning to address these periodic review factors after a final decision in this proceeding.

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[9] The issue involves line extensions and the portion of costs paid by developers (and customers) versus the utility (and ratepayers). Line extension cost recovery rules include an option where the developer may pay an amount upfront as a nonrefundable deposit based on a discount from the estimated total cost. The current discount is 50%. Applicant's experience appears to show that this option leaves a net cost for ratepayers, and TURN sought to include the issue of its elimination. We note that the percentage may change over time based on several factors included in PG&E's tariff. Alternatively, the percentage might be increased to 100% if appropriate (i.e., elimination of the discount option) based on public policy or other considerations.

[10] PG&E's Electric Tariff Rule 15.I.2 states:

> "PERIODIC REVIEW. PG&E will periodically review the factors it uses to determine its residential allowances, non-refundable discount option percentage rate, and Cost-of-Service Factor stated in this rule. If such review results in a change of more than five percent (5%), PG&E will submit a tariff revision proposal to the Commission for review and approval. Such proposed changes shall be submitted no sooner than six (6) months after the last revision.

Footnote continued on next page

In the March 30, 2005 Ruling, the ALJ proposed including an ordering paragraph in this decision to ensure that the issue is not lost, and a forum is presented for its consideration, even if PG&E determines that the change should be less than 5%. We need not adopt the ALJ's proposal here, however. We have already separately required PG&E to file an application to examine line extension matters. (Resolution E-3921, dated June 16, 2005.) TURN can pursue the issue there.

7. Comments on Proposed Decision

On September 30, 2005, the proposed decision of ALJ Burton W. Mattson was filed and served on parties in accordance with Public Utilities Code Section 311(d) and Rule 77.1 of the Commission's Rules of Practice and Procedure. Comments were filed and served on October 20, 2005 by PG&E and Settling Parties. We make minor corrections as recommended, including to Attachment A in Appendix D (illustrative rates for the Supplemental Small Light and Power Settlement). No reply comments were filed.

8. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner. Burton W. Mattson is the assigned ALJ in this proceeding.

"Additionally, PG&E shall submit by advice letter proposed tariff revisions, which result from other relevant Commission decisions, to the allowance formula for calculating line and service extension allowances."

Findings of Fact

1. On February 17, 2005, applicant served notice on all parties of a settlement conference, and on March 9, 2005 applicant hosted the initial settlement conference, with additional discussions held over the course of several weeks.

2. 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).

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

4. Settling Parties to the May 13, 2005 Settlement are all the active parties; include residential, small commercial, large commercial, agricultural and industrial customers, and are thereby fairly reflective of the affected interests; and the May 13, 2005 Settlement along with the record contain sufficient information for the Commission to discharge its future regulatory duties.

5. The record consists of over 80 exhibits, plus testimony at evidentiary hearing over two days from panels of expert witnesses in support of individual settlements.

6. Settling Parties do not agree on specific marginal costs, but generally agree that the residential class is bearing less than its full cost of service while most non-residential classes are bearing more than their full cost of service and, based on this general concurrence regarding costs, agree to a revenue allocation that brings electric rates into better alignment with costs while at the same time tempering the magnitude and abruptness of changes to any one customer class.

7. There is no dispute that the record shows charging full cost by any party's measure of marginal costs means increases to the residential class with decreases to other classes for the revenue neutral allocation in this proceeding.

8. The approximate 4.5% increase for the residential class resulting from the May 13, 2005 Settlement is below even the smallest "full cost" increase estimated by any party, and is in the mid-range of the outcomes recommended in the parties' litigation positions.

9. The recommended revenue allocation is reasonable in light of the whole record.

10. Rate design outcomes reflect one or another party's position, or a compromise between parties, and are reasonable in light of the whole record.

11. No party objects to any settlement.

12. The May 13, 2005 Settlement and five Supplemental Settlements are in the public interest (e.g., by being a reasonable compromise of litigation positions, avoiding the cost of further litigation, conserving scarce resources, moderating potentially harsh bill impacts while better aligning rates with costs, avoiding a residential class rate decrease inconsistent with cost as would result from application of RDSA principles, retaining residential class total revenue at less than energy crisis levels, avoiding an increase in CARE rates).

13. CCDC seeks continuation of the eligibility period for standby charge exemptions authorized by statute (§ 353 et seq.) and extended by the Commission (D.03-04-060) until the Commission issues a decision regarding establishment of DG rates in R.04-03-017 (or any other proceeding where DG tariffs are considered), and such rates become effective, notwithstanding any approved standby rates in this proceeding (A.04-06-024).

14. PG&E has been ordered to file an application regarding line extension issues. (Resolution E-3921.)

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 May 13, 2005 Settlement meets the four all-party settlement tests and should be adopted.

4. The Commission's currently adopted revenue allocation policies apply only prior to adoption of rates in this proceeding.

5. The settlements are consistent with law and Commission decisions (e.g., Water Code § 80110; Pub. Util. Code §§ 451, 453, 739, 739.1, 739.2, 739.5, 739.7; D.03-07-028, D.04-02-062, and D.05-06-029).

6. The May 13, 2005 Settlement and five Supplemental Settlements are reasonable in light of the whole record, consistent with law, and in the public interest, and should be adopted.

7. The relief requested by CCDC should be granted.

8. This order should be effective immediately so that applicant may prepare the necessary advice letter, parties may review and comment on that advice letter, and rates may be timely adjusted consistent with the adopted Settlements.

INTERIM ORDER

IT IS ORDERED that:

1. The motions dated May 13, June 3, and July 8, 2005 for adoption of the May 13, 2005 Settlement plus five Supplemental Settlements are granted. The Settlements in Appendices B, C, D, E, F and G are adopted.

2. Within 45 days of the date this order is mailed, Pacific Gas and Electric Company (PG&E or applicant) shall file an advice letter(s) in compliance with General Order 96-A and Decision (D.) 05-01-032 ("Third Interim Opinion Adopting Certain Requirements Regarding Advice Letter Filing, Service, Suspension, and Disposition"). The advice letter(s) shall also comply with resolutions, if any, adopted pursuant to applicant's annual electric true-up filing (Advice 2706-E filed September 1, 2005). The advice letter(s) shall include revised tariff sheets to implement the revenue allocations and rate designs adopted in this order. The tariff sheets shall become effective on or after January 1, 2006, subject to Energy Division determining that they are in compliance with this order.

3. Notwithstanding any Commission approval of standby rates in this proceeding, the eligibility period for standby charge exemptions authorized by statute and extended by the Commission in D.03-04-060 shall remain in effect until (a) distributed generation rates established by Commission decision become effective, consistent with the policies adopted in D.01-07-027 and with any cost-benefit analysis methodology developed in Rulemaking 04-03-017, or (b) until further order of the Commission.

4. Applicant shall provide notice to customers on Schedule E-25 consistent with the discussion in this order.

5. This proceeding remains open to address the agricultural class definition issue.

This order is effective today.

Dated ____________________________, at San Francisco, California.