

ATTACHMENT 1
SUPPLEMENTAL SETTLEMENT AGREEMENT
ON RESIDENTIAL RATE DESIGN ISSUES

**SUPPLEMENTAL SETTLEMENT AGREEMENT ON RESIDENTIAL
RATE DESIGN ISSUES
IN PG&E'S APPLICATION 06-03-005**

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Residential Rate Design Settlement Agreement (Settling Parties, Residential Settlement) agree on a mutually acceptable outcome to the residential rate design issues in Application (A.) 06-03-005, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. This Residential Settlement is supplemental to the Settlement in A. 06-03-005 filed in this proceeding on February 9, 2007 (February 9 Settlement), in that it uses the revenue allocation agreed to in the February 9 Settlement and addresses residential rate issues that were not resolved in the February 9 Settlement. The Settling Parties intend that the complementary outcomes of this Residential Settlement and the February 9 Settlement be consolidated in the Commission's final decision in this proceeding. The details of this Residential Settlement are set forth herein.

II. SETTLING PARTIES

The Settling Parties are as follows:

- California Solar Energy Industries Association (CAL SEIA)
- Division of Ratepayer Advocates (DRA)
- Pacific Gas and Electric Company (PG&E)
- PV Now (PV Now)
- The Utility Reform Network (TURN)
- Vote Solar

- The Western Manufactured Housing Communities Association (WMA)

III. SETTLEMENT CONDITIONS

This Residential Settlement resolves the issues raised by the Settling Parties in A.06-03-005 on residential rate design, subject to the conditions set forth below:

1. This Residential Settlement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters. This Residential Settlement builds on the underlying marginal cost and revenue allocation in the February 9 Settlement and incorporates that agreement by reference.
2. This Residential Settlement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts and law presented by the Settling Parties in this proceeding. This Residential Settlement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.
3. The Settling Parties agree that this Residential Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest.
4. The Settling Parties agree that no provision of this Residential Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
5. This Residential Settlement may be amended or changed only by a written agreement signed by the Settling Parties.
6. The Settling Parties shall jointly request Commission approval of this Residential Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required,

comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The Settling Parties intend the Residential Settlement to be interpreted and treated as a unified, integrated agreement incorporating the February 9 Settlement, which forms the foundation for the residential rate design agreed to herein. In the event the Commission rejects or modifies this Residential Settlement or the underlying February 9 Settlement, the Settling Parties reserve their rights under CPUC Rule 12.4.

IV. SETTLEMENT HISTORY

In its Test Year 2007 General Rate Case (GRC) Application 05-12-002, PG&E proposed that the proceeding be separated into two distinct phases: Phase 1, which would cover the revenue requirement testimony submitted with that application, and Phase 2, which would cover electric marginal costs, revenue allocation, and rate design. The Assigned Commissioner's Ruling and Scoping Memo in A.05-12-002 directed PG&E to file its marginal costs, revenue allocation, and rate design proposals as a new application rather than as a separate phase.

Consistent with the Assigned Commissioner's Ruling in A.05-12-022, PG&E filed Application 06-03-005 on March 2, 2006, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended to "continue progress toward cost based, efficient pricing, while taking into consideration equity among customers and customer acceptance." The application was protested on March 27, 2006, by DRA.

A prehearing conference was held in the proceeding on May 3, 2006 before Administrative Law Judge (ALJ) Fukutome and Assigned Commissioner Rachelle Chong. The scope of the proceeding and procedural schedule were set forth in the

Assigned Commissioner's Ruling and Scoping Memo dated May 25. In compliance with the Scoping Memo, PG&E updated its showing on June 26. DRA served prepared testimony on September 13. Intervenors AECA, BOMA, CAC, CAL-SLA, CFBF, CLECA, CLFP, CMTA-ICP, DACC, EPUC, FEA, PV Now, TURN, Vote Solar, and WMA served their prepared testimony on October 27.

Meanwhile, on September 20, PG&E held a meet and confer session with all parties as well as Commission staff, as directed in the Scoping Memo. After providing notice pursuant to Rule 12.1(b), PG&E conducted additional settlement discussions pursuant to Article 12 of the CPUC's rules with the active parties to the proceeding. On November 1, PG&E held a mandatory settlement conference pursuant to the Scoping Memo. Based on the settlement discussions, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated November 9 and December 14, 2006.

On January 4, 2007, parties to the settlement discussions reached agreement in principle on the terms of a Settlement Agreement respecting electric marginal costs and revenue allocation. The following day, PG&E's counsel notified ALJ Fukutome that the active parties to the proceeding had reached settlement in principle regarding those issues and requested a further extension of the procedural schedule to memorialize that settlement and continue their efforts to reach agreement on rate design issues. ALJ Fukutome granted the request by written ruling dated January 10, 2007. In that ruling ALJ Fukutome allowed the parties until March 16, 2007, in which to file a settlement of rate design issues. On February 9, 2007, 22 parties filed a Settlement Agreement respecting marginal costs and revenue allocation (February 9 Settlement). They stated that discussions would continue in an effort to reach agreement on rate design issues.

After several discussions, the Settling Parties to this Residential Settlement reached an agreement in principle, building from the revenue allocation agreed to in the February 9 Settlement.

V. RESIDENTIAL SETTLEMENT TERMS GENERALLY

The Settling Parties agree that the rate design for the residential class embodied in this Residential Settlement takes the revenue allocation reached for that class in the February 9 Settlement and ensures that it is fully recovered through residential rates in a manner that is just and reasonable, in the public interest, and that reflects a reasonable compromise of Settling Parties' proposals. The Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Table 5 of the February 9 Settlement, which is based on estimated March 1, 2007 effective rates. The Settling Parties agree that the actual rates derived pursuant to this Residential Settlement shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the residential class and will differ from the rates presented herein. However, these actual rates shall be based on the residential rate structure described below. Illustrative rates for the residential class are set forth in Exhibit A to this Residential Settlement.

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

The Settling Parties further agree that this Residential Settlement resolves all residential rate design issues in A.06-03-005.

VI. RESIDENTIAL RATE DESIGN SETTLEMENT TERMS

A. Total bundled residential California Alternate Rates for Energy (CARE) rates will remain unchanged subject to the provisions of the February 9 Settlement.

B. Residential baseline quantities shall be revised in accordance with PG&E's testimony, subject to the restrictions on charges to residential customers for usage up to 130 percent of baseline as provided by Assembly Bill AB 1X. The electric and gas target baseline quantities provided in Exhibit (PG&E-3), Table 3-2 shall be adopted. The parties agree to phase in baseline quantities, together with appropriate revenue neutral rate adjustments, beginning on May 1, 2008 for electric and April 1, 2008 for gas, subject to receiving a decision in this proceeding leaving adequate time for implementation. Phase in will continue in subsequent years as necessary on May 1 for electric and April 1 for gas until target quantities are achieved. Prior to implementing the change in baseline quantities described herein, residential sales and associated rates will be based on then currently effective baseline quantities.

C. In PG&E's 2003 GRC Phase 2 proceeding (A.04-06-024), PG&E, WMA, TURN and DRA, among others, filed a settlement agreement on May 13, 2005 (2003 Phase 2 Revenue Allocation Settlement), resolving revenue allocation and certain specific rate design issues raised in that proceeding. In Section V.4.f of the 2003 Phase 2 Revenue Allocation Settlement, the parties agreed, among other things, that (1) "the master-meter discount for electric Schedule ET-Mobilehome Park Service shall be fixed at \$0.379 per space per day until the next applicable GRC Phase 2 proceeding"; (2) the "net master-meter discount for electric Schedule ES – Multifamily Service (for other than mobile home parks)

shall be fixed at the current level or \$0.10579 per unit per day... and shall be fixed at these levels until the next applicable GRC”; and (3) “[o]n or before July 1, 2007, PG&E shall update the data used to calculate the diversity benefit adjustment using sample metered data for directly metered mobile home parks, in consultation with WMA and TURN regarding the characteristics of the sample data, and shall submit a new diversity benefit study to the CPUC in PG&E’s next GRC Phase 2 proceeding or in another rate design proceeding.”

Since the autumn of 2005, PG&E, TURN and WMA have been working cooperatively to develop a new diversity benefit study, consistent with the terms of the 2003 Phase 2 Revenue Allocation Settlement. As of the date of this Residential Settlement, however, the diversity benefit study has not been completed. Rather than litigate issues related to the electric master meter discount in PG&E’s 2007 GRC Phase2 proceeding, PG&E, WMA, TURN and DRA agree that the master meter discount for Schedules ET and ES agreed to in the 2003 Phase 2 Revenue Allocation Settlement should continue in place until a new electric master meter discount is adopted in another PG&E rate design proceeding, such as PG&E’s next Biennial Cost Allocation Proceeding (BCAP) or the Electric Rate Design Window proceeding. PG&E, WMA, TURN and DRA further agree that the deadline for completing the new diversity benefit study should be extended by one month to August 1, 2007.

PG&E, WMA, TURN and DRA agree to work cooperatively to reach agreement on the appropriate new electric master meter discount, taking into account the results of the new diversity benefit study. If the parties reach agreement on a new electric master meter discount, they will memorialize the terms in a formal

settlement agreement, which will be filed with the CPUC and subject to formal approval. Alternatively, if the parties do not reach agreement, PG&E will promptly file its proposal for a new electric master meter discount in a future rate design proceeding, such as PG&E's BCAP or Electric Rate Design Window proceeding.

D. Total bundled rates for usage up to 130 percent of baseline will not be changed so long as the rate restrictions of AB 1X are effective, subject only to the increase to total bundled non-CARE rates for usage up to 130 percent of baseline for the California Solar Initiative (CSI) as described in Item G below. While the rate restrictions of AB 1X are in effect, revenue increases to the residential class will be implemented as proportional changes to the generation surcharges in Tiers 3, 4 and 5 as required to collect the revenue allocated to the residential class. Revenue reductions to the residential class will be implemented by not changing rates for usage up to 130 percent of baseline, and by proportionally reducing generation surcharges in Tiers 3, 4 and 5 to ensure the proper revenue is collected from residential class.

E. Should a reduction to the residential class in excess of three percent be expected, PG&E will consult with DRA and TURN to determine the proper method of allocating that revenue between tiers, provided however, that rates for usage up to 130 percent of baseline shall not be reduced. Should DRA, TURN and PG&E be unable to agree on the method to allocate the revenue reduction between tiers, PG&E will implement the change in the manner described in Part D, above.

F. Distribution and generation rates for non-CARE rate schedules in the residential class shall be differentiated by tier. Distribution and generation revenue on non-CARE rate schedules shall be collected in each rate tier in the same proportion as the generation and distribution revenue is allocated to each rate schedule, prior to determining rates for the CSI as described in item G.

G. Changes to total rates charged to the first 130 percent of baseline usage have been calculated as a compromise of positions between the parties in consideration of Public Utilities Code Section 2851 (d) (2). The Settling Parties took into consideration the total CSI revenue requirement in 2007 and the methods used to set total residential rates in the past, the net incremental solar costs created by the implementation of new CSI revenue requirements, a reduction in revenue requirements for the Self Generation Incentive Program, the revised inter-class allocation methodology for CSI and SGIP costs contained in the February 9 settlement, and an appropriate methodology for spreading these costs among all rate tiers. Accordingly, the Settlement Parties agree to increase total non-CARE rates in each tier by the negotiated CSI rate. The CSI rate will be determined as an equal proportion of pre-CSI distribution revenue in each tier as required to collect the CSI revenue allocated to the non-CARE residential schedules. The CSI exemption for customers taking service on the Family Electric Rate Assistance (FERA) program will be applied as a percentage of each customer's distribution energy charges (excluding charges or credits for the rate reduction bond memorandum account). CSI discounts provided to FERA customers will be accrued in the FERA balancing account and collected from residential customer distribution rates in the Annual Electric True Up filing.

H. PG&E's proposal to revise the Minimum Average Rate Limiter (MARL) for residential master metered customers that receive a submeter discount shall be adopted as set forth in Exhibit (PG&E-3), Chapter 3F.

I. To comply with D.05-12-041, residential rates for CARE are designed to reflect the CARE discount (including the discount provided currently as distribution and the discount currently provided as generation) in distribution rates. The CARE surcharge is then designed to collect the amount of this discount as set forth in the February 9 Settlement. In this Residential Settlement, CARE distribution rates are set to minimize the case where CARE customers taking Direct Access (DA) and Community Choice Aggregation (CCA) service would receive a negative utility bill. This is accomplished on CARE rate schedules that are subject to a minimum charge by setting a negative distribution rate that has an absolute value no greater than the positive charges to be paid by these customers. The utility charge for DA and CCA customers taking service on master-meter CARE rate schedules or on Schedule EL-8 will be no less than zero.

J. Ongoing Time-of-Use (TOU) meter charges applicable to voluntary residential TOU rate schedules will no longer be applied as each customer's Advanced Meter Infrastructure (AMI) meter is installed and used for billing.

K. PG&E's proposal to revise the franchise fee surcharge calculation, as set forth in Exhibit (PG&E-3), pages 1-15 and 1-16, shall be adopted for DA and CCA service.

L. Schedules E-7 and EL-7 shall be closed to new enrollment on the date Schedules E-6 and EL-6 that result from this proceeding are implemented. The Settling Parties agree that the revised Schedules E-6 and EL-6 fulfill the requirements of Senate Bill (SB) 1, Public Utilities Code Section 2851 (a)(4), requiring “a time-variant tariff that creates the maximum incentive for ratepayers to install solar systems...” This Settlement does not restrict parties from taking positions they deem appropriate in a subsequent proceeding that addresses time-variant rates, provided that prior to the next GRC Phase 2 proceeding, no Settling Party may argue that Schedules E-6 and EL-6 do not meet the SB-1 requirement for “a time-variant tariff that creates the maximum incentive for ratepayers to install solar systems.”

M. The Settling Parties agree that customers are required to take service on a TOU rate schedule in order to receive CSI incentives for installing solar systems. Accordingly, in addition to the TOU alternatives described above, the Settlement Parties agree to establish a time-of-use schedule for multifamily accounts currently eligible to take service under Schedules EM or EML. These new rate options would utilize the same rates and TOU periods established for Schedules E-6 and EL-6, but would be eligible for multiple baseline allowances. The applicable baseline allowances would be those adopted for Schedules EM and EML.

N. The Settling Parties agree that the Commission shall not require that customers taking service on submetered Schedules ET, ES, ESR or their CARE counterpart schedules take service on TOU options in order to receive CSI incentives. The Commission has not made TOU options available to these customers in the past and the Settling Parties agree that the submetering of tenants creates complications that cannot easily be addressed at this time.

O. Schedule E-9 is revised in accordance with the rates shown in Exhibit A. Further, the Settling Parties agree to clarify the applicability language in Schedule E9.

Replace the current text: "This experimental schedule applies to electric service to customers for whom Schedule E-1 applies and who refuel a low emission vehicle (LEV) at their premises. An LEV is either an electric vehicle (EV) or a natural gas vehicle (NGV)."

With the following clarification: "This experimental schedule applies to electric service to customers for whom Schedule E-1 applies and have a currently registered Motor Vehicle, as defined by the California Motor Vehicle Code, which is exclusively fueled with electricity (electric vehicle or EV) or natural gas (natural gas vehicle or NGV). Low Speed Electric Vehicles, as defined by the California Motor Vehicle Code, are not eligible for this rate option."

P. The illustrative rates shown in Exhibit A are developed to collect the same revenue allocated to the residential class that was used for the February 9 Settlement. The actual rates developed to implement this decision will vary based on the then current adopted revenue requirements.

Q. Timing of Rate Changes: Certain elements of this Residential Settlement require employee training and/or changes to PG&E systems beyond a normal change to a rate value. These changes include: (1) the FERA exemption in item (G); (2) the revision to MARL in item (H); (3) the application of a zero minimum charge and related CARE changes in item (I); (4) discontinuing the ongoing TOU meter charge in item (J); (5) revision of the franchise fee surcharge calculation in item (K); and (6) creating new multifamily TOU options as noted in item (M). These systems and program changes will be implemented by PG&E diligently as time permits and in a manner consistent with maintaining the secure, smooth operations of the systems involved. The Settling Parties recognize that some initiatives could take several months to implement.

VII. TIMING OF RATE CHANGE

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the February 9 Settlement, Section VII 2, shall apply to this Residential Settlement, unless specifically noted above.

VIII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This Residential Settlement shall become effective among the Settling Parties on the date

the last Settling Party executes the Residential Settlement, as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Residential Settlement on behalf of the Settling Parties they represent.

The undersigned represent that they are authorized to sign on behalf of the Party represented.

California Solar Energy Industries Association

By: _____ /s/
Gary Gerber

Title: _____ V.P.

Date: _____ 3/15/07

Division of Ratepayer Advocates

By: _____ /s/
Dana Appling

Title: _____ Director

Date: _____ 3/15/07

Pacific Gas and Electric Company

By: _____ /s/
Dan Pease

Title: _____ Manager, Electric Rates

Date: _____ 3/16/07

PV Now

By: _____ /s/
Joseph Wiedman

Title: _____ Attorney

Date: _____ 3/16/07

The Utility Reform Network

By: _____ /s/
Staff Attorney

Title: _____ Matt Freedman

Date: _____ 3/16/07

Vote Solar

By: _____ /s/
J. P. Ross

Title: _____ Director of Programs

Date: _____ 3/15/07

The Western Manufactured Housing
Communities Association

By: _____ /s/
Edward Poole

Title: _____ Attorney

Date: _____ 3/14/07

Residential Rate Design Settlement
Exhibit A

PROPOSED GRC PH2 SETTLEMENT

		BUNDLED					DIRECT ACCESS					
		Est. 3/1/07					DA					
		Total	Dist	PPP	Gen	Other	Total	Dist	PPP	CRS	Other	Proposed Total
Energy	T1	0.11430	\$0.03745	\$0.01048	\$0.04624	\$0.02126	\$0.11543	\$0.03745	\$0.01048	\$0.00810	\$0.01306	\$0.06909
	T2	0.12989	\$0.04451	\$0.01048	\$0.05498	\$0.02126	\$0.13124	\$0.04451	\$0.01048	\$0.00810	\$0.01306	\$0.07615
	T3	0.22723	\$0.09273	\$0.01048	\$0.11494	\$0.02126	\$0.23940	\$0.09273	\$0.01048	\$0.00810	\$0.01306	\$0.12437
	T4	0.31722	\$0.13730	\$0.01048	\$0.17035	\$0.02126	\$0.33939	\$0.13730	\$0.01048	\$0.00810	\$0.01306	\$0.16894
	T5	0.36438	\$0.16066	\$0.01048	\$0.19940	\$0.02126	\$0.39179	\$0.16066	\$0.01048	\$0.00810	\$0.01306	\$0.19230
MARL					\$0.03678	\$0.01214	\$0.04892			\$0.00810	\$0.00394	\$0.01204
Min Bill	\$/mtr/mo	\$4.50	\$3.58	\$0.14	\$0.78	\$0.00	\$4.50	\$3.58	\$0.14			\$3.72
	\$/kWh				(\$0.02092)	\$0.02092	\$0.00000			\$0.00810	\$0.01272	\$0.02082

		BUNDLED					DIRECT ACCESS						
		Est. 3/1/07					DA						
		Total	Dist	PPP	Gen	Other	Total	Dist	PPP	CRS	DA PCIA	Other	Proposed Total
Energy	T1	0.08316	(\$0.00205)	\$0.00572	\$0.06292	\$0.01657	\$0.08316	(\$0.00205)	\$0.00572	\$0.00351	(\$0.00010)	\$0.01306	\$0.02014
	T2	0.09563	(\$0.00205)	\$0.00572	\$0.07539	\$0.01657	\$0.09563	(\$0.00205)	\$0.00572	\$0.00351	(\$0.00010)	\$0.01306	\$0.02014
	T3	0.09563	(\$0.00205)	\$0.00572	\$0.07539	\$0.01657	\$0.09563	(\$0.00205)	\$0.00572	\$0.00351	(\$0.00010)	\$0.01306	\$0.02014
	T4	0.09563	(\$0.00205)	\$0.00572	\$0.07539	\$0.01657	\$0.09563	(\$0.00205)	\$0.00572	\$0.00351	(\$0.00010)	\$0.01306	\$0.02014
	T5	0.09563	(\$0.00205)	\$0.00572	\$0.07539	\$0.01657	\$0.09563	(\$0.00205)	\$0.00572	\$0.00351	(\$0.00010)	\$0.01306	\$0.02014
MARL					\$0.04147	\$0.00745	\$0.04892			\$0.00351	(\$0.00010)	\$0.00394	\$0.00735
Min Bill	\$/mtr/mo	\$3.60	\$2.68	\$0.07	\$0.84	\$0.00	\$3.60	\$2.68	\$0.07				\$2.75
	\$/kWh				(\$0.01623)	\$0.01623	\$0.00000			\$0.00351	(\$0.00010)	\$0.01272	\$0.01613

Residential Rate Design Settlement
Exhibit A

E-7

BUNDLED

DIRECT ACCESS

ENERGY

		Est. 3/1/07					Proposed
		Total	Dist	PPP	Gen	Other	Total
Smr Peak	T1	0.29372	\$0.09379	\$0.01026	\$0.17220	\$0.02126	\$0.29752
	T2	0.29372	\$0.09379	\$0.01026	\$0.17220	\$0.02126	\$0.29752
	T3	0.39106	\$0.13185	\$0.01026	\$0.24239	\$0.02126	\$0.40576
	T4	0.48105	\$0.16703	\$0.01026	\$0.30727	\$0.02126	\$0.50582
	T5	0.52821	\$0.18547	\$0.01026	\$0.34127	\$0.02126	\$0.55827
Smr Off-Peak	T1	0.08664	\$0.01975	\$0.01026	\$0.03617	\$0.02126	\$0.08744
	T2	0.08664	\$0.01975	\$0.01026	\$0.03617	\$0.02126	\$0.08744
	T3	0.18398	\$0.05781	\$0.01026	\$0.10635	\$0.02126	\$0.19569
	T4	0.27397	\$0.09299	\$0.01026	\$0.17123	\$0.02126	\$0.29575
	T5	0.32113	\$0.11143	\$0.01026	\$0.20524	\$0.02126	\$0.34819
Smr Baseline Credit		(0.01559)	(\$0.01582)				(\$0.01582)
Wtr Peak	T1	0.11472	\$0.02979	\$0.01026	\$0.05461	\$0.02126	\$0.11593
	T2	0.11472	\$0.02979	\$0.01026	\$0.05461	\$0.02126	\$0.11593
	T3	0.21206	\$0.06785	\$0.01026	\$0.12480	\$0.02126	\$0.22417
	T4	0.30205	\$0.10303	\$0.01026	\$0.18968	\$0.02126	\$0.32423
	T5	0.34921	\$0.12147	\$0.01026	\$0.22368	\$0.02126	\$0.37668
Wtr Off-Peak	T1	0.08966	\$0.02083	\$0.01026	\$0.03815	\$0.02126	\$0.09051
	T2	0.08966	\$0.02083	\$0.01026	\$0.03815	\$0.02126	\$0.09051
	T3	0.18700	\$0.05889	\$0.01026	\$0.10834	\$0.02126	\$0.19875
	T4	0.27699	\$0.09407	\$0.01026	\$0.17322	\$0.02126	\$0.29881
	T5	0.32415	\$0.11251	\$0.01026	\$0.20722	\$0.02126	\$0.35125
Wtr Baseline Credit		(0.01559)	(\$0.01582)				(\$0.01582)
Min Bill	\$/mtr/mo \$/kWh	\$4.50 \$3.94	\$0.14	\$0.42 (\$0.02092)	\$0.00	\$0.00 \$0.02092	\$4.50 \$0.0000

		Dist	PPP	DA CRS	Other	Proposed Total
Smr Peak	T1	\$0.09379	\$0.01026	\$0.00810	\$0.01306	\$0.12521
	T2	\$0.09379	\$0.01026	\$0.00810	\$0.01306	\$0.12521
	T3	\$0.13185	\$0.01026	\$0.00810	\$0.01306	\$0.16327
	T4	\$0.16703	\$0.01026	\$0.00810	\$0.01306	\$0.19845
	T5	\$0.18547	\$0.01026	\$0.00810	\$0.01306	\$0.21689
Smr Off-Peak	T1	\$0.01975	\$0.01026	\$0.00810	\$0.01306	\$0.05117
	T2	\$0.01975	\$0.01026	\$0.00810	\$0.01306	\$0.05117
	T3	\$0.05781	\$0.01026	\$0.00810	\$0.01306	\$0.08923
	T4	\$0.09299	\$0.01026	\$0.00810	\$0.01306	\$0.12441
	T5	\$0.11143	\$0.01026	\$0.00810	\$0.01306	\$0.14285
Smr Baseline Credit		(\$0.01582)				(\$0.01582)
Wtr Peak	T1	\$0.02979	\$0.01026	\$0.00810	\$0.01306	\$0.06121
	T2	\$0.02979	\$0.01026	\$0.00810	\$0.01306	\$0.06121
	T3	\$0.06785	\$0.01026	\$0.00810	\$0.01306	\$0.09927
	T4	\$0.10303	\$0.01026	\$0.00810	\$0.01306	\$0.13445
	T5	\$0.12147	\$0.01026	\$0.00810	\$0.01306	\$0.15289
Wtr Off-Peak	T1	\$0.02083	\$0.01026	\$0.00810	\$0.01306	\$0.05225
	T2	\$0.02083	\$0.01026	\$0.00810	\$0.01306	\$0.05225
	T3	\$0.05889	\$0.01026	\$0.00810	\$0.01306	\$0.09031
	T4	\$0.09407	\$0.01026	\$0.00810	\$0.01306	\$0.12549
	T5	\$0.11251	\$0.01026	\$0.00810	\$0.01306	\$0.14393
Wtr Baseline Credit		(\$0.01582)				(\$0.01582)
Min Bill		\$3.94	\$0.14	\$0.00810	0.00 \$0.01272	\$4.08 \$0.02082

EL-7

ENERGY

		Est. 3/1/07					Proposed
		Total	Dist	PPP	Gen	Other	Total
Smr Peak	T1	0.28372	(\$0.01809)	\$0.01026	\$0.27498	\$0.01657	\$0.28372
	T2	0.28372	(\$0.01809)	\$0.01026	\$0.27498	\$0.01657	\$0.28372
	T3	0.28372	(\$0.01809)	\$0.01026	\$0.27498	\$0.01657	\$0.28372
	T4	0.28372	(\$0.01809)	\$0.01026	\$0.27498	\$0.01657	\$0.28372
	T5	0.28372	(\$0.01809)	\$0.01026	\$0.27498	\$0.01657	\$0.28372
Smr Off-Peak	T1	0.07664	(\$0.01809)	\$0.01026	\$0.06790	\$0.01657	\$0.07664
	T2	0.07664	(\$0.01809)	\$0.01026	\$0.06790	\$0.01657	\$0.07664
	T3	0.07664	(\$0.01809)	\$0.01026	\$0.06790	\$0.01657	\$0.07664
	T4	0.07664	(\$0.01809)	\$0.01026	\$0.06790	\$0.01657	\$0.07664
	T5	0.07664	(\$0.01809)	\$0.01026	\$0.06790	\$0.01657	\$0.07664
Smr Baseline Credit		(0.01559)	(\$0.01559)				(\$0.01559)
Wtr Peak	T1	0.10472	(\$0.01809)	\$0.01026	\$0.09598	\$0.01657	\$0.10472
	T2	0.10472	(\$0.01809)	\$0.01026	\$0.09598	\$0.01657	\$0.10472
	T3	0.10472	(\$0.01809)	\$0.01026	\$0.09598	\$0.01657	\$0.10472
	T4	0.10472	(\$0.01809)	\$0.01026	\$0.09598	\$0.01657	\$0.10472
	T5	0.10472	(\$0.01809)	\$0.01026	\$0.09598	\$0.01657	\$0.10472
Wtr Off-Peak	T1	0.07966	(\$0.01809)	\$0.01026	\$0.07092	\$0.01657	\$0.07966
	T2	0.07966	(\$0.01809)	\$0.01026	\$0.07092	\$0.01657	\$0.07966
	T3	0.07966	(\$0.01809)	\$0.01026	\$0.07092	\$0.01657	\$0.07966
	T4	0.07966	(\$0.01809)	\$0.01026	\$0.07092	\$0.01657	\$0.07966
	T5	0.07966	(\$0.01809)	\$0.01026	\$0.07092	\$0.01657	\$0.07966
Wtr Baseline Credit		(0.01559)	(\$0.01559)				(\$0.01559)
Min Bill	\$/mtr/mo \$/kWh	\$4.50 \$3.94	\$0.14	\$0.42 (\$0.01623)	\$0.00	\$0.00 \$0.01623	\$4.50 \$0.0000

		Dist	PPP	DA CRS	DA PCIA	Other	Proposed Total
Smr Peak	T1	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T2	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T3	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T4	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T5	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
Smr Off-Peak	T1	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T2	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T3	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T4	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T5	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
Smr Baseline Credit		(\$0.01559)					(\$0.01559)
Wtr Peak	T1	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T2	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T3	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T4	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T5	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
Wtr Off-Peak	T1	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T2	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T3	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T4	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
	T5	(\$0.01809)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00864
Wtr Baseline Credit		(\$0.01559)					(\$0.01559)
Min Bill		\$3.94	\$0.14	\$0.00351	(\$0.00010)	0.00 \$0.01272	\$4.08 \$0.01613

Residential Rate Design Settlement
Exhibit A

E-8

BUNDLED

DIRECT ACCESS

ENERGY
Summer

T1
T2
T3
T4
T5

Est. 3/1/07 Total	Dist	PPP	Gen	Other	Proposed Total
0.11815	\$0.01476	\$0.01099	\$0.07229	\$0.02126	\$0.11930
0.11815	\$0.01476	\$0.01099	\$0.07229	\$0.02126	\$0.11930
0.21549	\$0.03302	\$0.01099	\$0.16215	\$0.02126	\$0.22742
0.30548	\$0.04990	\$0.01099	\$0.24521	\$0.02126	\$0.32736
0.35264	\$0.05875	\$0.01099	\$0.28875	\$0.02126	\$0.37975

Winter

T1
T2
T3
T4
T5

0.07577	\$0.00749	\$0.01099	\$0.03661	\$0.02126	\$0.07635
0.07577	\$0.00749	\$0.01099	\$0.03661	\$0.02126	\$0.07635
0.17311	\$0.02575	\$0.01099	\$0.12647	\$0.02126	\$0.18447
0.26310	\$0.04263	\$0.01099	\$0.20954	\$0.02126	\$0.28442
0.31026	\$0.05148	\$0.01099	\$0.25307	\$0.02126	\$0.33680

CUSTOMER

\$/mtr/mo

\$12.53	\$12.53				\$12.53
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Dist	PPP	DA CRS	Other	Proposed Total
\$0.01476	\$0.01099	\$0.00810	\$0.01306	\$0.04691
\$0.01476	\$0.01099	\$0.00810	\$0.01306	\$0.04691
\$0.03302	\$0.01099	\$0.00810	\$0.01306	\$0.06517
\$0.04990	\$0.01099	\$0.00810	\$0.01306	\$0.08205
\$0.05875	\$0.01099	\$0.00810	\$0.01306	\$0.09090
\$0.00749	\$0.01099	\$0.00810	\$0.01306	\$0.03964
\$0.00749	\$0.01099	\$0.00810	\$0.01306	\$0.03964
\$0.02575	\$0.01099	\$0.00810	\$0.01306	\$0.05790
\$0.04263	\$0.01099	\$0.00810	\$0.01306	\$0.07478
\$0.05148	\$0.01099	\$0.00810	\$0.01306	\$0.08363
\$12.53				\$12.53

EL-8

ENERGY
Summer

T1
T2
T3
T4
T5

Est. 3/1/07 Total	Dist	PPP	Gen	Other	Proposed Total
0.08624	(\$0.10095)	\$0.00623	\$0.16439	\$0.01657	\$0.08624
0.08624	(\$0.10095)	\$0.00623	\$0.16439	\$0.01657	\$0.08624
0.08624	(\$0.10095)	\$0.00623	\$0.16439	\$0.01657	\$0.08624
0.08624	(\$0.10095)	\$0.00623	\$0.16439	\$0.01657	\$0.08624
0.08624	(\$0.10095)	\$0.00623	\$0.16439	\$0.01657	\$0.08624

Winter

T1
T2
T3
T4
T5

0.05234	(\$0.10095)	\$0.00623	\$0.13049	\$0.01657	\$0.05234
0.05234	(\$0.10095)	\$0.00623	\$0.13049	\$0.01657	\$0.05234
0.05234	(\$0.10095)	\$0.00623	\$0.13049	\$0.01657	\$0.05234
0.05234	(\$0.10095)	\$0.00623	\$0.13049	\$0.01657	\$0.05234
0.05234	(\$0.10095)	\$0.00623	\$0.13049	\$0.01657	\$0.05234

CUSTOMER

\$/mtr/mo

\$10.02	\$10.02				\$10.02
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Dist	PPP	DA CRS	DA PCIA	Other	Proposed Total
(\$0.10095)	\$0.00623	\$0.00351	(\$0.00010)	\$0.01306	(\$0.07825)
(\$0.10095)	\$0.00623	\$0.00351	(\$0.00010)	\$0.01306	(\$0.07825)
(\$0.10095)	\$0.00623	\$0.00351	(\$0.00010)	\$0.01306	(\$0.07825)
(\$0.10095)	\$0.00623	\$0.00351	(\$0.00010)	\$0.01306	(\$0.07825)
(\$0.10095)	\$0.00623	\$0.00351	(\$0.00010)	\$0.01306	(\$0.07825)
(\$0.10095)	\$0.00623	\$0.00351	(\$0.00010)	\$0.01306	(\$0.07825)
(\$0.10095)	\$0.00623	\$0.00351	(\$0.00010)	\$0.01306	(\$0.07825)
(\$0.10095)	\$0.00623	\$0.00351	(\$0.00010)	\$0.01306	(\$0.07825)
(\$0.10095)	\$0.00623	\$0.00351	(\$0.00010)	\$0.01306	(\$0.07825)
(\$0.10095)	\$0.00623	\$0.00351	(\$0.00010)	\$0.01306	(\$0.07825)
\$10.02					\$10.02

Residential Rate Design Settlement
Exhibit A

		BUNDLED					DIRECT ACCESS					
		Est. 3/1/07				Proposed				Proposed		
		Total	Dist	PPP	Gen	Other	Total	Dist	PPP	DA	Other	Total
								CRS				
ENERGY												
Smr Peak	T1	0.32260	\$0.10412	\$0.01026	\$0.19117	\$0.02126	\$0.32681	\$0.10412	\$0.01026	\$0.00810	\$0.01306	\$0.13554
	T2	0.32260	\$0.10412	\$0.01026	\$0.19117	\$0.02126	\$0.32681	\$0.10412	\$0.01026	\$0.00810	\$0.01306	\$0.13554
	T3	0.41994	\$0.14218	\$0.01026	\$0.26136	\$0.02126	\$0.43506	\$0.14218	\$0.01026	\$0.00810	\$0.01306	\$0.17360
	T4	0.50993	\$0.17736	\$0.01026	\$0.32624	\$0.02126	\$0.53512	\$0.17736	\$0.01026	\$0.00810	\$0.01306	\$0.20878
	T5	0.55709	\$0.19580	\$0.01026	\$0.36024	\$0.02126	\$0.58756	\$0.19580	\$0.01026	\$0.00810	\$0.01306	\$0.22722
Smr Off-Peak	T1	0.08248	\$0.01826	\$0.01026	\$0.03344	\$0.02126	\$0.08322	\$0.01826	\$0.01026	\$0.00810	\$0.01306	\$0.04968
	T2	0.08248	\$0.01826	\$0.01026	\$0.03344	\$0.02126	\$0.08322	\$0.01826	\$0.01026	\$0.00810	\$0.01306	\$0.04968
	T3	0.17982	\$0.05632	\$0.01026	\$0.10362	\$0.02126	\$0.19146	\$0.05632	\$0.01026	\$0.00810	\$0.01306	\$0.08774
	T4	0.26981	\$0.09150	\$0.01026	\$0.16850	\$0.02126	\$0.29152	\$0.09150	\$0.01026	\$0.00810	\$0.01306	\$0.12292
	T5	0.31697	\$0.10994	\$0.01026	\$0.20250	\$0.02126	\$0.34397	\$0.10994	\$0.01026	\$0.00810	\$0.01306	\$0.14136
Smr Baseline Credit		(0.01559)	(\$0.01582)				(\$0.01582)	(\$0.01582)				(\$0.01582)
Wtr Peak	T1	0.11393	\$0.02951	\$0.01026	\$0.05410	\$0.02126	\$0.11512	\$0.02951	\$0.01026	\$0.00810	\$0.01306	\$0.06093
	T2	0.11393	\$0.02951	\$0.01026	\$0.05410	\$0.02126	\$0.11512	\$0.02951	\$0.01026	\$0.00810	\$0.01306	\$0.06093
	T3	0.21127	\$0.06757	\$0.01026	\$0.12428	\$0.02126	\$0.22337	\$0.06757	\$0.01026	\$0.00810	\$0.01306	\$0.09899
	T4	0.30126	\$0.10275	\$0.01026	\$0.18916	\$0.02126	\$0.32343	\$0.10275	\$0.01026	\$0.00810	\$0.01306	\$0.13417
	T5	0.34842	\$0.12119	\$0.01026	\$0.22316	\$0.02126	\$0.37587	\$0.12119	\$0.01026	\$0.00810	\$0.01306	\$0.15261
Wtr Off-Peak	T1	0.08974	\$0.02086	\$0.01026	\$0.03820	\$0.02126	\$0.09058	\$0.02086	\$0.01026	\$0.00810	\$0.01306	\$0.05228
	T2	0.08974	\$0.02086	\$0.01026	\$0.03820	\$0.02126	\$0.09058	\$0.02086	\$0.01026	\$0.00810	\$0.01306	\$0.05228
	T3	0.18708	\$0.05892	\$0.01026	\$0.10839	\$0.02126	\$0.19883	\$0.05892	\$0.01026	\$0.00810	\$0.01306	\$0.09034
	T4	0.27707	\$0.09410	\$0.01026	\$0.17327	\$0.02126	\$0.29889	\$0.09410	\$0.01026	\$0.00810	\$0.01306	\$0.12552
	T5	0.32423	\$0.11254	\$0.01026	\$0.20727	\$0.02126	\$0.35133	\$0.11254	\$0.01026	\$0.00810	\$0.01306	\$0.14396
Wtr Baseline Credit		(0.01559)	(\$0.01582)				(\$0.01582)	(\$0.01582)				(\$0.01582)
Min Bill	\$/mtr/mo	\$4.50	\$3.94	\$0.14	\$0.42	\$0.00	\$4.50	\$3.94	\$0.14	\$0.00810	0.00	\$4.08
	\$/kWh				(\$0.02092)	\$0.02092	\$0.0000				\$0.01272	\$0.02082

		BUNDLED					DIRECT ACCESS						
		Est. 3/1/07				Proposed				Proposed			
		Total	Dist	PPP	Gen	Other	Total	Dist	PPP	DA	Other	Total	
								CRS		DA			
								PCIA					
ENERGY													
Smr Peak	T1	0.31260	(\$0.01978)	\$0.01026	\$0.30555	\$0.01657	\$0.31260	(\$0.01978)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00695
	T2	0.31260	(\$0.03537)	\$0.01026	\$0.32114	\$0.01657	\$0.31260	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T3	0.31260	(\$0.03537)	\$0.01026	\$0.32114	\$0.01657	\$0.31260	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T4	0.31260	(\$0.03537)	\$0.01026	\$0.32114	\$0.01657	\$0.31260	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T5	0.31260	(\$0.03537)	\$0.01026	\$0.32114	\$0.01657	\$0.31260	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
Smr Off-Peak	T1	0.07248	(\$0.01978)	\$0.01026	\$0.06543	\$0.01657	\$0.07248	(\$0.01978)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00695
	T2	0.07248	(\$0.03537)	\$0.01026	\$0.08102	\$0.01657	\$0.07248	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T3	0.07248	(\$0.03537)	\$0.01026	\$0.08102	\$0.01657	\$0.07248	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T4	0.07248	(\$0.03537)	\$0.01026	\$0.08102	\$0.01657	\$0.07248	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T5	0.07248	(\$0.03537)	\$0.01026	\$0.08102	\$0.01657	\$0.07248	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
Smr Baseline Credit		(0.01559)	(\$0.01559)				(\$0.01559)	(\$0.01559)				(\$0.01559)	
Wtr Peak	T1	0.10393	(\$0.01978)	\$0.01026	\$0.09688	\$0.01657	\$0.10393	(\$0.01978)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00695
	T2	0.10393	(\$0.03537)	\$0.01026	\$0.11247	\$0.01657	\$0.10393	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T3	0.10393	(\$0.03537)	\$0.01026	\$0.11247	\$0.01657	\$0.10393	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T4	0.10393	(\$0.03537)	\$0.01026	\$0.11247	\$0.01657	\$0.10393	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T5	0.10393	(\$0.03537)	\$0.01026	\$0.11247	\$0.01657	\$0.10393	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
Wtr Off-Peak	T1	0.07974	(\$0.01978)	\$0.01026	\$0.07269	\$0.01657	\$0.07974	(\$0.01978)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	\$0.00695
	T2	0.07974	(\$0.03537)	\$0.01026	\$0.08828	\$0.01657	\$0.07974	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T3	0.07974	(\$0.03537)	\$0.01026	\$0.08828	\$0.01657	\$0.07974	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T4	0.07974	(\$0.03537)	\$0.01026	\$0.08828	\$0.01657	\$0.07974	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
	T5	0.07974	(\$0.03537)	\$0.01026	\$0.08828	\$0.01657	\$0.07974	(\$0.03537)	\$0.01026	\$0.00351	(\$0.00010)	\$0.01306	(\$0.00864)
Wtr Baseline Credit		(0.01559)	(\$0.01559)				(\$0.01559)	(\$0.01559)				(\$0.01559)	
Min Bill	\$/mtr/mo	\$4.50	\$3.94	\$0.14	\$0.42	\$0.00	\$4.50	\$3.94	\$0.14	\$0.00351	0.00	\$4.08	
	\$/kWh				(\$0.01623)	\$0.01623	\$0.0000				\$0.01272	\$0.01613	

Residential Rate Design Settlement
Exhibit A

E-9A

BUNDLED

DIRECT ACCESS

		Est. 3/1/07					Proposed
		Total	Dist	PPP	Gen	Other	Total
ENERGY							
Smr Peak	T1	0.28368	\$0.09020	\$0.01026	\$0.16561	\$0.02126	\$0.28733
	T2	0.28368	\$0.09020	\$0.01026	\$0.16561	\$0.02126	\$0.28733
	T3	0.38102	\$0.12826	\$0.01026	\$0.23579	\$0.02126	\$0.39558
	T4	0.47101	\$0.16344	\$0.01026	\$0.30067	\$0.02126	\$0.49563
	T5	0.51817	\$0.18188	\$0.01026	\$0.33468	\$0.02126	\$0.54808
Smr Pt Peak	T1	0.10395	\$0.02594	\$0.01026	\$0.04754	\$0.02126	\$0.10500
	T2	0.10395	\$0.02594	\$0.01026	\$0.04754	\$0.02126	\$0.10500
	T3	0.20129	\$0.06400	\$0.01026	\$0.11773	\$0.02126	\$0.21325
	T4	0.29128	\$0.09918	\$0.01026	\$0.18260	\$0.02126	\$0.31330
	T5	0.33844	\$0.11762	\$0.01026	\$0.21661	\$0.02126	\$0.36575
Smr Off-Peak	T1	0.04965	\$0.00653	\$0.01026	(\$0.00399)	\$0.02126	\$0.03406
	T2	0.04965	\$0.00653	\$0.01026	\$0.01160	\$0.02126	\$0.04965
	T3	0.14699	\$0.04459	\$0.01026	\$0.02390	\$0.02126	\$0.10000
	T4	0.23698	\$0.07977	\$0.01026	\$0.03471	\$0.02126	\$0.14600
	T5	0.28414	\$0.09821	\$0.01026	\$0.05528	\$0.02126	\$0.18500
Smr Baseline Credit		(0.01559)	(\$0.01582)				(\$0.01582)
Wtr Pt Peak	T1	0.10383	\$0.02590	\$0.01026	\$0.04746	\$0.02126	\$0.10488
	T2	0.10383	\$0.02590	\$0.01026	\$0.04746	\$0.02126	\$0.10488
	T3	0.20117	\$0.06396	\$0.01026	\$0.11765	\$0.02126	\$0.21312
	T4	0.29116	\$0.09914	\$0.01026	\$0.18252	\$0.02126	\$0.31318
	T5	0.33832	\$0.11758	\$0.01026	\$0.21653	\$0.02126	\$0.36562
Wtr Off-Peak	T1	0.05795	\$0.00949	\$0.01026	\$0.00135	\$0.02126	\$0.04236
	T2	0.05795	\$0.00949	\$0.01026	\$0.01694	\$0.02126	\$0.05795
	T3	0.15529	\$0.04755	\$0.01026	\$0.02093	\$0.02126	\$0.10000
	T4	0.24528	\$0.08273	\$0.01026	\$0.03175	\$0.02126	\$0.14600
	T5	0.29244	\$0.10117	\$0.01026	\$0.05231	\$0.02126	\$0.18500
Wtr Baseline Credit		(0.01559)	(\$0.01582)				(\$0.01582)
Min Bill	\$/mtr/mo	\$4.50	\$3.94	\$0.14	\$0.42	\$0.00	\$4.50
	\$/kWh				(\$0.02092)	\$0.02092	\$0.00000

		Dist	PPP	DA	Other	Proposed
				CRS		Total
		\$0.09020	\$0.01026	\$0.00810	\$0.01306	\$0.12162
		\$0.09020	\$0.01026	\$0.00810	\$0.01306	\$0.12162
		\$0.12826	\$0.01026	\$0.00810	\$0.01306	\$0.15968
		\$0.16344	\$0.01026	\$0.00810	\$0.01306	\$0.19486
		\$0.18188	\$0.01026	\$0.00810	\$0.01306	\$0.21330
		\$0.02594	\$0.01026	\$0.00810	\$0.01306	\$0.05736
		\$0.02594	\$0.01026	\$0.00810	\$0.01306	\$0.05736
		\$0.06400	\$0.01026	\$0.00810	\$0.01306	\$0.09542
		\$0.09918	\$0.01026	\$0.00810	\$0.01306	\$0.13060
		\$0.11762	\$0.01026	\$0.00810	\$0.01306	\$0.14904
		\$0.00653	\$0.01026	\$0.00810	\$0.01306	\$0.03795
		\$0.00653	\$0.01026	\$0.00810	\$0.01306	\$0.03795
		\$0.04459	\$0.01026	\$0.00810	\$0.01306	\$0.07600
		\$0.07977	\$0.01026	\$0.00810	\$0.01306	\$0.11119
		\$0.09821	\$0.01026	\$0.00810	\$0.01306	\$0.12962
		(\$0.01582)				(\$0.01582)
		\$0.02590	\$0.01026	\$0.00810	\$0.01306	\$0.05732
		\$0.02590	\$0.01026	\$0.00810	\$0.01306	\$0.05732
		\$0.06396	\$0.01026	\$0.00810	\$0.01306	\$0.09538
		\$0.09914	\$0.01026	\$0.00810	\$0.01306	\$0.13056
		\$0.11758	\$0.01026	\$0.00810	\$0.01306	\$0.14900
		\$0.00949	\$0.01026	\$0.00810	\$0.01306	\$0.04091
		\$0.00949	\$0.01026	\$0.00810	\$0.01306	\$0.04091
		\$0.04755	\$0.01026	\$0.00810	\$0.01306	\$0.07897
		\$0.08273	\$0.01026	\$0.00810	\$0.01306	\$0.11415
		\$0.10117	\$0.01026	\$0.00810	\$0.01306	\$0.13259
		(\$0.01582)				(\$0.01582)
		\$3.94	\$0.14	\$0.00810	\$0.00	\$4.08
					\$0.01272	\$0.02082

E-9B

		Est. 3/1/07					Proposed
		Total	Dist	PPP	Gen	Other	Total
ENERGY							
Smr Peak	T1	0.27967	\$0.08877	\$0.01026	\$0.16297	\$0.02126	\$0.28326
	T2	0.27967	\$0.08877	\$0.01026	\$0.16297	\$0.02126	\$0.28326
	T3	0.37701	\$0.12683	\$0.01026	\$0.23316	\$0.02126	\$0.39151
	T4	0.46700	\$0.16201	\$0.01026	\$0.29804	\$0.02126	\$0.49157
	T5	0.51416	\$0.18045	\$0.01026	\$0.33204	\$0.02126	\$0.54401
Smr Pt Peak	T1	0.09994	\$0.02451	\$0.01026	\$0.04491	\$0.02126	\$0.10093
	T2	0.09994	\$0.02451	\$0.01026	\$0.04491	\$0.02126	\$0.10093
	T3	0.19728	\$0.06257	\$0.01026	\$0.11509	\$0.02126	\$0.20918
	T4	0.28727	\$0.09775	\$0.01026	\$0.17997	\$0.02126	\$0.30924
	T5	0.33443	\$0.11619	\$0.01026	\$0.21397	\$0.02126	\$0.36168
Smr Off-Peak	T1	0.05616	\$0.00885	\$0.01026	\$0.01615	\$0.02126	\$0.05652
	T2	0.05616	\$0.00885	\$0.01026	\$0.01615	\$0.02126	\$0.05652
	T3	0.15350	\$0.04691	\$0.01026	\$0.08633	\$0.02126	\$0.16476
	T4	0.24349	\$0.08209	\$0.01026	\$0.15121	\$0.02126	\$0.26482
	T5	0.29065	\$0.10053	\$0.01026	\$0.18521	\$0.02126	\$0.31726
Smr Baseline Credit		(0.01559)	(\$0.01582)				(\$0.01582)
Wtr Peak	T1	0.10027	\$0.02463	\$0.01026	\$0.04512	\$0.02126	\$0.10127
	T2	0.10027	\$0.02463	\$0.01026	\$0.04512	\$0.02126	\$0.10127
	T3	0.19761	\$0.04687	\$0.01026	\$0.13112	\$0.02126	\$0.20951
	T4	0.28760	\$0.08205	\$0.01026	\$0.19600	\$0.02126	\$0.30957
	T5	0.33476	\$0.10049	\$0.01026	\$0.23001	\$0.02126	\$0.36201
Wtr Off-Peak	T1	0.06378	\$0.01158	\$0.01026	\$0.02115	\$0.02126	\$0.06425
	T2	0.06378	\$0.01158	\$0.01026	\$0.02115	\$0.02126	\$0.06425
	T3	0.16112	\$0.04964	\$0.01026	\$0.09134	\$0.02126	\$0.17249
	T4	0.25111	\$0.08482	\$0.01026	\$0.15622	\$0.02126	\$0.27255
	T5	0.29827	\$0.10326	\$0.01026	\$0.19022	\$0.02126	\$0.32500
Wtr Baseline Credit		(0.01559)	(\$0.01582)				(\$0.01582)
Min Bill	\$/mtr/mo	\$4.50	\$3.94	\$0.14	\$0.42	\$0.00	\$4.50
	\$/kWh				(\$0.02092)	\$0.02092	\$0.00000

		Dist	PPP	DA	DA	Other	Proposed
				CRS	PCIA		Total
		\$0.08877	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.12009
		\$0.08877	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.12009
		\$0.12683	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.15815
		\$0.16201	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.19333
		\$0.18045	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.21177
		\$0.02451	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.05583
		\$0.02451	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.05583
		\$0.06257	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.09389
		\$0.09775	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.12907
		\$0.11619	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.14750
		\$0.00885	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.04017
		\$0.00885	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.04017
		\$0.04691	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.07823
		\$0.08209	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.11341
		\$0.10053	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.13185
		(\$0.01582)					(\$0.01582)
		\$0.02463	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.05594
		\$0.02463	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.05594
		\$0.04687	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.07819
		\$0.08205	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.11337
		\$0.10049	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.13181
		\$0.01158	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.04290
		\$0.01158	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.04290
		\$0.04964	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.08096
		\$0.08482	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.11614
		\$0.10326	\$0.01026	\$0.00810	(\$0.00010)	\$0.01306	\$0.13458
		(\$0.01582)					(\$0.01582)
		\$3.94	\$0.14	\$0.00810	(\$0.00010)	\$0.00	\$4.08
						\$0.01272	\$0.02072

ATTACHMENT 2
SUPPLEMENTAL SETTLEMENT AGREEMENT
ON STREETLIGHT RATE DESIGN ISSUES

**SUPPLEMENTAL SETTLEMENT AGREEMENT ON STREETLIGHT
RATE DESIGN ISSUES
IN PG&E'S APPLICATION 06-03-005**

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Streetlight Rate Design Settlement Agreement (Settling Parties, Streetlight Settlement) agree on a mutually acceptable outcome to the streetlight rate design issues in Application (A.) 06-03-005, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. This Streetlight Settlement is supplemental to the Settlement in A. 06-03-005 filed in this proceeding on February 9, 2007 (February 9 Settlement), in that it uses the revenue allocation agreed to in the February 9 Settlement and addresses streetlight rate design issues that were not resolved in the February 9 Settlement. The Settling Parties intend that the complementary outcomes of this Streetlight Settlement and the February 9 Settlement be consolidated in the Commission's final decision in this proceeding. The details of this Streetlight Settlement are set forth herein.

II. SETTLING PARTIES

The Settling Parties are as follows:

- California City-County Street Light Association (CAL-SLA)
- Pacific Gas and Electric Company (PG&E)

III. SETTLEMENT CONDITIONS

This Streetlight Settlement resolves the issues raised by the Settling Parties in A.06-03-005 on streetlight rate design, subject to the conditions set forth below:

1. This Streetlight Settlement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or

written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters. This Streetlight Settlement builds on the underlying marginal cost and revenue allocation in the February 9 Settlement and incorporates that agreement by reference.

2. This Streetlight Settlement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts and law presented by the Settling Parties in this proceeding. This Streetlight Settlement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.

3. The Settling Parties agree that this Streetlight Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest.

4. The Settling Parties agree that no provision of this Streetlight Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.

5. This Streetlight Settlement may be amended or changed only by a written agreement signed by the Settling Parties.

6. The Settling Parties shall jointly request Commission approval of this Streetlight Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The Settling Parties intend the Streetlight Settlement to be interpreted and treated as a unified, integrated agreement incorporating the February 9 Settlement, which forms the foundation for the streetlight rate design agreed to herein. In the event the Commission rejects or modifies this Streetlight Settlement or the underlying February 9 Settlement, the Settling Parties reserve their rights under CPUC Rule 12.4.

IV. SETTLEMENT HISTORY

In its Test Year 2007 General Rate Case (GRC) Application 05-12-002, PG&E proposed that the proceeding be separated into two distinct phases: Phase 1, which would cover the revenue requirement testimony submitted with that application, and Phase 2, which would cover electric marginal costs, revenue allocation, and rate design. The Assigned Commissioner's Ruling and Scoping Memo in A.05-12-002 directed PG&E to file its marginal costs, revenue allocation, and rate design proposals as a new application rather than as a separate phase.

Consistent with the Assigned Commissioner's Ruling in A.05-12-022, PG&E filed Application 06-03-005 on March 2, 2006, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended to "continue progress toward cost based, efficient pricing, while taking into consideration equity among customers and customer acceptance." The application was protested on March 27, 2006, by DRA.

A prehearing conference was held in the proceeding on May 3, 2006 before Administrative Law Judge (ALJ) Fukutome and Assigned Commissioner Rachelle Chong. The scope of the proceeding and procedural schedule were set forth in the Assigned Commissioner's Ruling and Scoping Memo dated May 25. In compliance with the Scoping Memo, PG&E updated its showing on June 26. DRA served prepared testimony on September 13. Intervenors AECA, BOMA, CAC, CAL-SLA, CFBF, CLECA, CLFP, CMTA-ICP, DACC, EPUC, FEA, PV Now, TURN, Vote Solar, and WMA served their prepared testimony on October 27.

Meanwhile, on September 20, PG&E held a meet and confer session with all parties as well as Commission staff, as directed in the Scoping Memo. After providing notice pursuant to Rule 12.1(b), PG&E conducted additional settlement discussions pursuant to Article 12 of the CPUC's rules with the active parties to the proceeding. On November 1, PG&E held a mandatory settlement conference pursuant to the Scoping

Memo. Based on the settlement discussions, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated November 9 and December 14, 2006.

On January 4, 2007, parties to the settlement discussions reached agreement in principle on the terms of a Settlement Agreement respecting electric marginal costs and revenue allocation. The following day, PG&E's counsel notified ALJ Fukutome that the active parties to the proceeding had reached settlement in principle regarding those issues and requested a further extension of the procedural schedule to memorialize that settlement and continue their efforts to reach agreement on rate design issues. ALJ Fukutome granted the request by written ruling dated January 10, 2007. In that ruling ALJ Fukutome allowed the parties until March 16, 2007, in which to file a settlement of rate design issues. On February 9, 2007, 22 parties filed a Settlement Agreement respecting marginal costs and revenue allocation (February 9 Settlement). They stated that discussions would continue in an effort to reach agreement on rate design issues.

After several discussions, on March 15 parties to this Streetlight Settlement reached an agreement in principle, building from the revenue allocation agreed to in the February 9 Settlement.

V. STREETLIGHT SETTLEMENT TERMS GENERALLY

The Settling Parties agree that the primary purpose of rate design for the streetlight class is to take the revenue allocation reached for that class in the February 9 Settlement and ensure that it is fully recovered through streetlight rates, including streetlight non-energy rates, in a manner that is just and reasonable, in the public interest, and reflects a reasonable compromise of Settling Parties' proposals. The Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Table 5 of the February 9 Settlement, which are based on estimated March 1, 2007 effective rates. The Settling Parties agree that the actual rates

derived pursuant to this Streetlight Settlement shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the streetlight class and will differ from the rates presented herein. However, these actual rates shall be based on the streetlight energy rate structure described below.

Illustrative energy rates for Schedules LS-1, LS-2, LS-3 and OL-1 are set forth in Exhibit A to this Streetlight Settlement. Final non-energy rates for Schedules LS-1, LS-2, OL-1, and the City and County of San Francisco are set forth in Exhibits A and B. The terms of this Settlement Agreement are reflected in draft tariffs, as appropriate, and are attached to this Streetlight Settlement as Exhibit C (Schedule LS-1), Exhibit D (Schedule LS-2), Exhibit E (Schedule LS-3), and Exhibit F (Schedule TC-1).

The Settling Parties agree that all testimony served prior to the date of this Streetlight Settlement that addresses the issues resolved by this Streetlight Settlement should be admitted into evidence without cross-examination by the Settling Parties. The Settling Parties further agree that this Streetlight Settlement resolves all streetlight issues in A.06-03-005.

VI. STREETLIGHT SETTLEMENT TERMS

A. Streetlight Non-Energy Rates: The Settling Parties agree to the non-energy streetlight rates set forth in Exhibits A and B to this Streetlight Settlement.

B. Rate Design for Schedules LS-1 and LS-2: The Settling Parties agree to the use of the following formula to calculate the energy charge for streetlights:

$$\text{streetlight energy rate per kilowatthour (kWh)} = ((\text{Lamp wattage} + \text{ballast wattage}) \times 4,100 \text{ hours} / 12 \text{ months} / 1000) \times$$

Draft tariffs reflecting the implementation of the formula, including ballast factors, are provided in Exhibits C and D.

C. Wattage Limitation for Schedule LS-2: The Settling Parties agree to an upper-most limit of 150 watts of non-conforming load on customer owned streetlight circuits. This upper limit on allowable wattage for non-conforming load is based on and will accommodate current governmental agencies interest in low wattage connections with limited energy demand. The Settling Parties agree to the definition of non-conforming load as set forth in Condition 3(f) of the draft Schedule LS-2 tariff attached as Exhibit D.

D. Traffic Control Rate Schedule: The Settling Parties agree to retain the name Schedule TC-1, Traffic Control Service.

E. The Settling Parties further agree to the following streetlight rate design matters as set forth in PG&E's direct testimony. Associated tariff changes are set forth in draft tariffs attached to this Settlement Agreement as Exhibits C through F.

- The Schedule TC-1 customer charge will be set at the proposed level for single phase service under Schedule A-1. Energy rates are then determined residually such that they do not vary seasonally by function or in total.¹
- The Schedule LS-3 customer charge will increase from \$3 per month to \$6 per month, expressed as a daily equivalent. The energy rate for Schedule LS-3 is set equal to the energy rate established for LS-1 and LS-2 and does not vary seasonally by function or total.
- On January 1 of each year following a decision in A.06-03-005, rates for the City and Count of San Francisco street lights on LS-1 or LS-2 or equivalent will be adjusted until the rates are set at the full cost, or until this issue is addressed and decided in a future GRC Phase 2 proceeding, whichever comes first. Final non-energy charges for City and County of

¹ Revenue allocation for Schedule TC-1 will be addressed as part of the Small Light and Power Rate Design Settlement.

San Francisco are shown in Exhibit B to this Streetlight Settlement.

- Eligibility for Schedule TC-1 will be revised to include general service loads on traffic control circuits whose energy requirements are constant over time (i.e. load that consumes energy at the same rate 24 hours a day, seven days a week) or are restricted to night-time use.
- Schedule TC-1 Condition 3 and Schedule LS-3 Condition 3 will be simplified by establishing annually an average allowance applicable to all customers. The allowances will be calculated using the average distribution revenue in the same manner as described in Application 10-05-016, testimony of Jamie Randolph, Chapter 2, pages 2-7 to 2-10.
- Schedule LS-1 Condition 13, Schedule LS-2 Condition 9, Schedule TC-1 Condition 6, and Schedule LS-3 Condition 6 shall be revised to allow installation of certain infrastructure required by local authorities in advance of actual subdivision work and bona fide loads. Payment and refund provisions will revert to the payment and refund provisions of Electric Rule 15.
- Schedule LS-1 Condition 9 will be amended to address attachments to street light poles for civic purposes. The appurtenances conditioned on a separate license agreement.
- Schedule LS-2 will only be applicable to governmental agencies. Schedule LS-2, Rate Class B, will be eliminated. Customers currently on Schedule LS-2, Rate Class B, will be allowed to choose Rate Class A or Rate Class C. Where the customer makes no choice, the customer will be placed on Rate Class C.
- Schedule LS-1 and Schedule LS-3 applicability will be expanded to allow streetlights in private areas to be served under these two schedules.
- Schedule LS-2 Condition 8 will be revised to reflect the elimination of Rate

Class B.

- Schedule LS-2 Condition 13 will be revised to eliminate the requirement that customers provide an inventory list of street lights.
- Schedule LS-1 Condition 3 and Schedule LS-2 Condition 7 will be revised to allow 24 hour operations.
- PG&E's proposal to revise the franchise fee surcharge calculation, as set forth in Exhibit (PG&E-3), pages 1-15, 1-16, shall be adopted for direct access and community choice aggregation service.

VII. TIMING OF RATE CHANGE

The provisions regarding the timing of rate change and rate changes between General Rate Cases agreed to in the February 9 Settlement, Section VII 2, shall apply to this Streetlight Settlement, unless specifically noted above.

VIII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This Streetlight Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the Streetlight Settlement, as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Streetlight Settlement on behalf of the Settling Parties they represent.

PACIFIC GAS AND ELECTRIC COMPANY
PHASE 2 OF THE 2007 GENERAL RATE CASE
STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT
EXHIBITS

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT
EXHIBIT A
Energy and Non-Energy Rates for Schedules LS-1, LS-2, LS-3 and OL-1

EXHIBIT A, Page 1

Non-Energy Charges for Schedules LS-1, LS-2 and OL-1

	Rate Schedule	Service	Plant Charge Per Month	Universal Charge	O&M Charge	Total Monthly Facility Charge
1	LS-1A	PG&E owns and maintains luminaire, control facilities, support arm, and service wiring on its existing distribution pole, and all lights	\$3.777	\$0.187	\$2.501	\$6.465
2	LS-1B	PG&E owns and maintains luminaire, control facilities, support arm, pole or post, foundation and service connection and where customer has paid the estimated installed cost of the luminaire, support arm and control facilities	\$2.268	\$0.187	\$2.501	\$4.956
3	LS-1C	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring as required (ownership of pole or post, support arm and foundation by customer).	\$2.260	\$0.187	\$2.501	\$4.948
4	LS-1D	PG&E owns and maintains its standard post top luminaire, control facility, internal post wiring, standard galvanized steel post (20-foot mounting height or less) and foundation where customer pays for the estimated and installed cost of the post, support arm (if any) and foundation	\$5.388	\$0.187	\$2.501	\$8.076
5	LS-1E	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring, service connection, galvanized steel pole and foundation where the customer has paid to PG&E the estimated installed cost of the pole, support arm and foundation.	\$4.914	\$0.187	\$2.501	\$7.603
6	LS-1F	PG&E owns and maintains a standard luminaire, control facility, support arm, and service connection on its wood pole or post, installed solely for the luminaire.	\$4.989	\$0.187	\$2.501	\$7.678
7	LS-2A	City Owned and Maintained	\$0.000	\$0.187		\$0.187
8	LS-2B & 2C	City Owned and PG&E Maintained	\$0.000	\$0.187	\$2.501	\$2.688
9	OL-1	Outdoor area lighting service where street lighting schedules are not applicable and where PG&E installs, owns, operates and maintains the complete lighting installation on PG&E's existing wood distribution poles or on customer-owned poles acceptable to PG&E installed by the customer on his private property.	\$3.777	\$0.187	\$2.501	\$6.465
10	SP-2A1			\$0.187		\$0.187

EXHIBIT A, Page 2

Energy Charges for Schedules LS-1, LS-2, LS-3 and OL-1 (\$/kilowatt-hour)

	Distribution	Generation	Public Purpose Programs	Other	Total
LS-1, LS-2, LS-3	\$0.02502	\$0.06658	\$0.00610	\$0.01297	\$0.11067
OL-1	\$0.02502	\$0.06658	\$0.01097	\$0.01297	\$0.11554

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT
EXHIBIT B
City and County of San Francisco Streetlight Rates

Streetlight Rate Design Settlement
EXHIBIT B, Page 1
City and County of San Francisco

Rate Schedule	Typical Lamp Type & Size	Full Cost	Present Rates	CCSF Proposed Rates			
				Year 1	Phase In*	Year 2	Phase In*
CCSF Rate Schedule No. 1 LS-1A	HIGH PRESSURE SODIUM VAPOR 100 WATTS 9,500 LUMENS	\$6.519	\$5.006	\$5.384	1/4	\$5.763	2/4
CCSF Rate Schedule No. 3 LS-1A	HIGH PRESSURE SODIUM VAPOR 150 WATTS 16,000 LUMENS	\$6.525	\$5.053	\$5.421	1/4	\$5.789	2/4
CCSF Rate Schedule No. 4E LS-1E	HIGH PRESSURE SODIUM VAPOR 100 WATTS 9,500 LUMENS	\$7.684	\$7.980	\$7.684	1/4	\$7.684	2/4
CCSF Rate Schedule No. 4A LS-1E	MERCURY VAPOR 175 WATTS 7,500 LUMENS	\$9.002	\$6.890	\$7.418	1/4	\$7.946	2/4
CCSF Rate Schedule No. 6 LS-2B	High Pressure Sodium Vapor 100 WATTS 9,500 LUMENS	\$2.688	\$2.095	\$2.243	1/4	\$2.392	2/4
Nonstandard - No PG&E Equivalent CCSF Rate Schedule No. 4A	Incandescent: 295 WATTS 4,000 LUMENS	\$8.500	\$5.049	\$5.739	1/5	\$6.429	2/5
	Mercury Vapor: 400 WATTS 21,000 LUMENS	\$8.804	\$7.942	\$8.114	1/5	\$8.287	2/5
CCSF Rate Schedule No. 5	High Pressure Sodium Vapor 100 WATTS 9,500 LUMENS	\$8.932	\$4.906	\$5.711	1/5	\$6.516	2/5
	Incandescent: 405 WATTS 6,000 LUMENS	\$10.171	\$6.271	\$7.051	1/5	\$7.831	2/5
CCSF Rate Schedule No. 6 (Chinatown Area)	High Pressure Sodium Vapor 250 WATTS 28,000 LUMENS	\$74.094	\$16.158	\$27.745	1/5	\$39.332	2/5
CCSF Rate Schedule No. 7			Based on Time & Material				
CCSF Rate Schedule No. 9 (Triangle District)	High Pressure Sodium Vapor 150W 16,000 LUMENS DUPLEX (1)	\$29.029	\$7.720	\$11.982	1/5	\$16.244	2/5
	150W 16,000 LUMENS DUPLEX (2)	\$3.750	\$2.850	\$3.030	1/5	\$3.210	2/5

Notes: The rate(s) for each City and County of San Francisco rate schedule is based on a typical lamp within each rate schedule.

Phase-in: Numerator of fraction identifies number of years the phase-in has occurred.

Denominator of fraction identifies span of years for the phase-in period.

Streetlight Rate Design Settlement
EXHIBIT B, Page 2
City and County of San Francisco

Rate Schedule	Typical Lamp Type & Size	Year 3	CCSF Proposed Rates				
			Phase In*	Year 4	Phase In*	Year 5	Phase In*
CCSF Rate Schedule No. 1 LS-1A	HIGH PRESSURE SODIUM VAPOR 100 WATTS 9,500 LUMENS	\$6.141	3/4	\$6.519	4/4		
CCSF Rate Schedule No. 3 LS-1A	HIGH PRESSURE SODIUM VAPOR 150 WATTS 16,000 LUMENS	\$6.157	3/4	\$6.525	4/4		
CCSF Rate Schedule No. 4E LS-1E	HIGH PRESSURE SODIUM VAPOR 100 WATTS 9,500 LUMENS	\$7.684	3/4	\$7.684	4/4		
CCSF Rate Schedule No. 4A LS-1E	MERCURY VAPOR 175 WATTS 7,500 LUMENS	\$8.474	3/4	\$9.002	4/4		
CCSF Rate Schedule No. 6 LS-2B	High Pressure Sodium Vapor 100 WATTS 9,500 LUMENS	\$2.540	3/4	\$2.688	4/4		
Nonstandard - No PG&E Equivalent CCSF Rate Schedule No. 4A	Incandescent: 295 WATTS 4,000 LUMENS	\$7.119	3/5	\$7.809	4/5	\$8.500	5/5
	Mercury Vapor: 400 WATTS 21,000 LUMENS	\$8.459	3/5	\$8.632	4/5	\$8.804	5/5
CCSF Rate Schedule No. 5	High Pressure Sodium Vapor 100 WATTS 9,500 LUMENS	\$7.321	3/5	\$8.127	4/5	\$8.932	5/5
	Incandescent: 405 WATTS 6,000 LUMENS	\$8.611	3/5	\$9.391	4/5	\$10.171	5/5
CCSF Rate Schedule No. 6 (Chinatown Area)	High Pressure Sodium Vapor 250 WATTS 28,000 LUMENS	\$50.92 0	3/5	\$62.507	4/5	\$74.094	5/5
CCSF Rate Schedule No. 7							
CCSF Rate Schedule No. 9 (Triangle District)	High Pressure Sodium Vapor 150W 16,000 LUMENS DUPLEX (1)	\$20.50 5	3/5	\$24.767	4/5	\$29.029	5/5
	150W 16,000 LUMENS DUPLEX (2)	\$3.390	3/5	\$3.570	4/5	\$3.750	5/5

Notes: The rate(s) for each City and County of San Francisco rate schedule is based on a typical lamp within each rate schedule.

Phase-in: Numerator of fraction identifies number of years the phase-in has occurred.

Denominator of fraction identifies span of years for the phase-in period.

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT

EXHIBIT C

Electric Rate Schedule LS-1



SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING

APPLICABILITY: This schedule is applicable to PG&E-owned and maintained lighting installations which illuminate streets, highways, and other outdoor ways and places and which generally utilize PG&E's distribution facilities under the provisions contained below. Rates of Class A through Class F service will be applicable as determined in Special Condition 4. (T)
(T)

TERRITORY: The entire territory served.

RATES: Rates are separated into two parts: facility and energy. (N)

Monthly facility charges include the costs of owning, operating and maintaining the various lamp types and size. Monthly energy charges are based on the kWh usage of each lamp.

Monthly energy charges per lamp are calculated using the following formula: (Lamp wattage + ballast wattage) x 4,100 hours/12 months/1000 x streetlight energy rate per kilowatt hour (kWh). Ballast wattage = ballast factor x lamp wattage.

Total bundled monthly energy charges for the most common lamps billed by PG&E on the approval date of this tariff are shown below. Subsequent additional lamps billed within the wattage ranges listed in the ballast factor table will be calculated using the same formula shown above.

The various ballast wattages used in the monthly energy charge calculations can be found in the Ballast Factor table following the monthly energy charges. Ballast factors are averaged within each grouping (range of wattages). The same ballast factor is applied to all of the lamps that fall within its watt range. Applicant or Customer must provide third party documentation where manufacturer's information is not available for rated wattage consumption before PG&E will accept lamps for this schedule.

Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with Condition 17 'Billing' below. (N)

(D)

Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

(D)

(Continued)



SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES: (Cont'd.)

CLASS	Facilities Charge Per Lamp Per Month					F	(N) (N)
	A	B	C**	D	E		
	\$6.465	\$4.956	\$4.948	\$8.076	\$7.603		

Nominal Lamp Rating	Energy Charge Per Lamp Per Month					Half-Hour Adjustment
	All Night Rates					
LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS	All Classes			

INCANDESCENT LAMPS*:

58	20	600	TBD	(N)	TBD	(R)
92	31	1,000	TBD		TBD	
189	65	2,500	TBD		TBD	
295	101	4,000	TBD		TBD	
405	139	6,000	TBD		TBD	

MERCURY VAPOR LAMPS*:

100	40	3,500	TBD		TBD	
175	68	7,500	TBD		TBD	
250	97	11,000	TBD		TBD	
400	152	21,000	TBD		TBD	
700	266	37,000	TBD		TBD	

HIGH PRESSURE SODIUM VAPOR LAMPS:

120 Volts						
70	29	5,800	TBD		TBD	
100	41	9,500	TBD		TBD	
150	60	16,000	TBD		TBD	
240 Volts						
70	34	5,800	TBD		TBD	
200	81	22,000	TBD		TBD	
250	100	25,500	TBD		TBD	
400	154	46,000	TBD	(N)	TBD	(R)

* Closed to new installations as of June 8, 1978, except where PG&E and customer shall agree, mercury vapor lamps may be installed under Class A and C to provide compatibility with existing light sources.

** Closed to new installation. See Special Condition 4.

(Continued)



SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES: (Cont'd.)

Ballast Factors by Lamp Type and Watt Range (N)

<u>Watt Range</u>	<u>Ballast Factor</u>	(N)	<u>Watt Range</u>	<u>Ballast Factor</u>	(N)
<u>MERCURY VAPOR</u>			<u>HIGH PRESSURE SODIUM VAPOR</u>		
1 to 75	31.00%	(N)	<u>120 Volts</u>		
76 to 125	17.07%		1 to 40	25.44%	(N)
126 to 325	13.69%		41 to 60	22.93%	
326 to 800	11.22%		61 to 85	21.25%	
801 +	10.34%		86 to 125	20.00%	
<u>LOW PRESSURE SODIUM VAPOR</u>			126 +	17.07%	
1 to 40	75.61%		<u>240 Volts</u>		
41 to 75	54.32%		1 to 60	40.49%	
76 to 110	46.34%		61 to 85	42.16%	
111 to 160	34.42%		86 to 125	37.56%	
161 +	26.83%		126 to 175	34.63%	
<u>METAL HALIDE</u>			176 to 225	18.54%	
0 to 85	25.44%		226 to 280	17.07%	
86 to 200	20.39%		281 to 380	12.35%	
201 to 375	22.93%		381 +	12.68%	
376 to 700	18.54%				
701 +	13.27%	(N)			(N)

* Closed to new installations as of June 8, 1978, except where PG&E and Customer shall agree, mercury vapor lamps may be installed under Class A and C to provide compatibility with existing light sources.

**Closed to new installations.

(Continued)



SCHEDULE LS-1-PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES: (Cont'd.)

TOTAL ENERGY RATES

Total Energy Charge Rate (\$ per kWh)	TBD	(T)
---------------------------------------	-----	-----

UNBUNDLING OF TOTAL ENERGY CHARGES

The total energy charge is unbundled according to the component rates shown below.

Energy Rate by Components (\$ per kWh)

Generation	TBD	(T)
Distribution	TBD	
Transmission*	TBD	
Transmission Rate Adjustments* (all usage)	TBD	
Reliability Services*	TBD	
Public Purpose Programs	TBD	
Nuclear Decommissioning	TBD	
Competition Transition Charge	TBD	
Energy Cost Recovery Amount	TBD	
DWR Bond	TBD	(T)

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)



SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

MORE THAN ONE LIGHT ON A POLE:

Where more than one light is installed on a pole, all lights other than the first will be billed on the Class C rate. Not applicable to installations made prior to September 11, 1978.

SPECIAL CONDITIONS:

1. **TYPE OF SERVICE:** (a) PG&E provides basic lighting services with limited standard facilities, pole types and configurations. Applicants may view standard offerings at PG&E local offices or online at PGE.com; (b) Applicant or Customer is responsible for lighting pattern layout and coverage for safety considerations; and (c) PG&E reserves the right to supply either "multiple" or "series" service. Series service to new lights will only be made where it is practical from PG&E's engineering standpoint to supply them from existing series systems.
2. **ANNUAL OPERATING SCHEDULE:** The above rates for All-Night (AN) service assume an average of approximately 11 hours operation per night and apply to lamps which will be turned on and off once each night in accordance with a regular operating schedule agreeable to the Customer but not exceeding 4,100 hours per year. This is also predicated on an electronic type photo control meeting ANSI standard C.136.10, with a turn on value of 1.0 footcandles and turn off value of 1.5 foot candles. Electro mechanical or thermal type photo controls are not acceptable for this rate schedule.
3. **OPERATING SCHEDULES OTHER THAN ALL-NIGHT:** Rates for regular operating schedules other than full AN will be the AN rate plus or minus, respectively, the half-hour adjustment for each half-hour more or less than an average of approximately 11 hours per night. This adjustment will apply only to lamps on regular operating schedules of not less than 1,095 hours per year, or three hours per night, and may be applied for 24-hour operation.

(N)

(Continued)

Advice Letter No.
Decision No.

Issued by
Brian K. Cherry
Vice President
Regulatory Relations

Date Filed _____
Effective _____
Resolution No. _____



SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

4. **DESCRIPTION OF SERVICE PROVIDED**

The following describes lighting facilities only. Lighting facilities payments, and service connections and payments, are described in Special Conditions 7, 8 and 9.

Class A: PG&E owns and maintains luminaire, control facilities, support arm, and service wiring on its existing distribution pole, and all lights formerly served under Schedule LS-1, Class A, as of September 11, 1978. There is no installation charge for this class.

Class B: PG&E owns and maintains luminaire, control facilities, support arm, pole or post, foundation and service connection and where Customer has paid the estimated installed cost of the luminaire, support arm and control facilities (applicable only to installations in service as of September 11, 1978).

Class C: Closed to new mixed ownership installations as of March 1, 2006. Only used for multiple lights on PG&E-owned poles to avoid duplicate billing of poles.

Class D: PG&E owns and maintains its standard post top luminaire, control facility, internal post wiring, standard post (20-foot mounting height or less) and foundation, underground or overhead circuit.

Class E: PG&E owns and maintains its standard luminaire, control facility, internal pole wiring, standard pole and foundation, underground or overhead circuit.

Class F: PG&E owns and maintains a standard luminaire, control facility, support arm, and service connection on its standard pole or post, installed solely for the luminaire.

(Continued)



SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

- 5. **REARRANGEMENT OF FACILITIES:** For any relocation, or rearrangement of PG&E's existing streetlight or service facilities at the request of the Customer and agreed to by PG&E, Customer shall pay PG&E, in advance, PG&E's estimated total cost of the relocation or rearrangement.
- 6. **SERVICE REQUESTS:** Service requests shall include form 72-1007 or 72-1008 for installation, removals, energizing and de-energizing of streetlight facilities.
- 7. **SERVICE AND LIGHTING INSTALLATION RESPONSIBILITIES:** The Applicant at its expense shall perform all necessary trenching, backfill and paving, and shall furnish and install all necessary conduit, and substructures, including substructures for transformer installations if necessary, for street light service and circuits, in accordance with PG&E's specifications. Upon acceptance by PG&E, ownership of the conduit and substructures will automatically transfer to PG&E. Riser material is installed by PG&E at the Customer's expense. Tree trimming is the responsibility of the Applicant.

PG&E will furnish and install the underground or overhead service conductor, transformers and necessary facilities to complete the service from the distribution line source subject to the payment provision of Special condition 8.

PG&E will establish service delivery points in close proximity to its distribution system as follows:

OVERHEAD: (a) In an overhead area—a single drop will be installed; and (b) for an overhead to underground system, service will be established in a PG&E box at the base of the pole, or directly to a single light or to the first light of a multiple circuit based on PG&E's standard design, in the shortest most practical configuration from the connection on the distribution line source.

UNDERGROUND: For an underground area, service will be established at the nearest existing secondary box. Where no secondary facilities exist, a new service, transformer and secondary splice box, as required, will be installed in the shortest most practical configuration from the connection on the distribution line source.

The Customer shall provide rights of way, clear route and access acceptable to PG&E in accordance with the provisions of electric Rule 16, and Special Condition 11 below.

Line or service extensions not conforming to the foregoing descriptions shall be installed under Special Condition 13.

(Continued)



SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

8. **NON REFUNDABLE PAYMENT FOR SERVICE POINT INSTALLATION**

- a) The Applicant shall pay in advance the estimated installed cost of facilities necessary to establish a service delivery point to serve the street light or street light circuit, minus a one-time revenue allowance based on the kWh of energy usage and the distribution component of the energy rate posted in the rate schedule for the lamps installed. The total allowance shall be determined by taking the annual equivalent kWh multiplied by the distribution component, then divided by the cost of service factor used in electric Rule 15.C.
- b) The allowance may only be provided where PG&E must install service facilities to connect street lights or street light circuits. No allowance will be provided where a simple connection is required, or in the case of a Class A installation. Only lights operating at a minimum on the full 11hour AN schedule shall be granted allowances. Where Applicant received allowances based upon 11 hour AN operation, no billing adjustments, as otherwise provided for in Special Condition 3, shall be made for the first three (3) years following commencement of service.

9. **PAYMENT FOR INSTALLATION OF LIGHTING FACILITIES:** PG&E will provide at its expense the luminaire kit and standard arm for LS-1A and LS-1C for second and multiple lights on a PG&E pole, for Class LS-1D, a standard post top, for Class LS-1E a luminaire kit, and for Class LS-1F a luminaire kit and standard arm. Customer or Applicant shall pay, in advance, the estimated installed cost of the remaining lighting facilities that PG&E is required to install. Allowances are not applied to street light facilities on the load side of the service delivery point.

Any attachments to street light poles requested by governmental agencies, requires prior approval by PG&E and execution of a license agreement. Unauthorized attachments are subject to removal.

(N)
|
(N)

(Continued)



SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

10. **OWNERSHIP:** All facilities installed under the provisions of this rate schedule shall be owned, operated and maintained by PG&E.

11. **MAINTENANCE, ACCESS, CLEARANCES**

- a) Maintenance: PG&E shall exercise reasonable care and diligence in maintaining PG&E-owned facilities.
- b) Access: Customer will maintain adequate access for PG&E's standard equipment used in maintaining facilities and for installation of its facilities. PG&E reserves the right to collect additional maintenance costs due to obstructed access or other conditions preventing PG&E from maintaining its equipment with standard operating procedures. Applicant or Customer shall be responsible for rearrangement charges as provided for in Special Condition 5.
- c) Clearances: Customer will, at Customers expense, correct all access or clearance infractions, or pay PG&E's total estimated cost for PG&E to relocate facilities to a new location which is acceptable to PG&E. Failure to comply with corrective measures within a reasonable time may result in discontinuance of service in accordance with electric Rule 11. Applicant or Customer shall be responsible for tree trimming to maintain lighting patterns of existing lights.

12. **SPECIAL EQUIPMENT:** Luminaires, poles, posts and other equipment requested by an Applicant or Customer in addition to or in substitution for PG&E's standard poles, posts, photo controls and equipment, will be provided if such equipment meets PG&E's engineering and operating standards, and if PG&E agrees to do so, provided that the Applicant or Customer pays the cost difference between the equipment normally installed by PG&E and the equipment requested by the Applicant or Customer, plus an additional Cost of Ownership payment as provided for in Section I.3 of electric Rule 2. This provision is also applicable to special optical filters, shields or other special hardware required or requested by the Applicant or Customer or any governmental agency having jurisdiction.

13. **LINE EXTENSIONS**

- A. Where PG&E extends its facilities to street light installations in advance of subdivision projects where subdivision maps have been approved by local authorities, extensions will be installed under the provisions of electric Rule 15, except as noted below.
- B. Where PG&E extends its facilities to street light installations in the absence of any approved subdivision maps, applicant shall pay PG&E's estimated cost, plus cost of ownership and applicable tax. Standard form contract 62-4527, Agreement to Perform Tariff Schedule Related Work shall be used for these installations.

(N)

(N)

(D)

(Continued)



SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

- 14. **TEMPORARY DISCONTINUANCE OF SERVICE:** (Fixture remains in place.) At the request of the Customer, PG&E will temporarily discontinue service to the individual luminaires provided the Customer pays a facility charge equal to the all-night rate, adjusted to zero burning hours under the provisions of Special Condition 3, plus the estimated cost to disconnect and reconnect the light.
- 15. **CONTRACT:** Except as otherwise provided in this rate schedule, or where lighting service is installed in conjunction with facilities installed under the provisions of Rules 15 or 16, standard form contract 62-4527, Agreement to Perform Tariff Schedule Related Work shall be used for installations, rearrangements or relocations.
- 16. **MINIMUM SERVICE PERIOD:** Temporary services will be installed under electric Rule 13.
- 17. **BILLING:** A Customer's bill is calculated based on the option applicable to the Customer. Payment will be made in accordance with PG&E's filed tariffs.

Bundled Service Customers receive supply and delivery service solely from PG&E. The customer's bill is based on the Total Rates and Conditions set forth in this schedule.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, the FTA (where applicable), the RRBMA (where applicable), the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

(Continued)



SCHEDULE LS-1—PG&E-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

17. **BILLING** (Cont'd.)

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, the FTA (where applicable), the RRBMA (where applicable), the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

	DA CRS	CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	TBD	TBD	(T)
Power Charge Indifference Adjustment (per kWh)	TBD	TBD	
DWR Bond Charge (per kWh)	TBD	TBD	
CTC Charge (per kWh)	TBD	TBD	
Total CRS (per kWh)	TBD	TBD	(T)

18. **DWR BOND CHARGE:** The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts.

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT

EXHIBIT D

Electric Rate Schedule LS-2



SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

APPLICABILITY: This schedule is applicable service to lighting installations which illuminate streets, highways, and other publicly-dedicated outdoor ways and places where the Customer is a Governmental Agency and owns the lighting fixtures, poles and interconnecting circuits. The Customer's facilities must be of good construction acceptable to PG&E and in satisfactory condition to qualify for Class C rates. Class C is closed to new installations and additional lamps in existing accounts. (T)

TERRITORY: The entire territory served. (T)

RATES: Rates are separated into two parts: facility and energy. (N)

Monthly facility charges include the costs of owning, operating and maintaining the various lamp types and size. Monthly energy charges are based on the kWh usage of each lamp.

Monthly energy charges per lamp are calculated using the following formula: (Lamp wattage + ballast wattage) x 4,100 hours/12 months/1000 x streetlight energy rate per kilowatt hour (kWh). Ballast wattage = ballast factor x lamp wattage.

Total bundled monthly energy charges for the most common lamps billed by PG&E on the approval date of this tariff are shown below. Subsequent additional lamps billed within the wattage ranges listed in the ballast factor table will be calculated using the same formula shown above.

The various ballast wattages used in the monthly energy charge calculations can be found in the Ballast Factor table following the monthly energy charges. Ballast factors are averaged within each grouping (range of wattages). The same ballast factor is applied to all of the lamps that fall within its watt range. Applicant or Customer must provide third party documentation where manufacturer's information is not available for rated wattage consumption before PG&E will accept lamps for this schedule. (N)

Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with Condition 13 'Billing' below. (D)

(L)

(Continued)



SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES: (Cont'd.)

CLASS	Facilities Charge Per Lamp Per Month		(N)
	A	C**	
	\$0.187	\$2.688	

CLASS:	Energy Charge Per Lamp Per Month All Night Rates		(N)
	A	C	
PG&E supplies energy and service only.	(N)	PG&E supplies the energy and maintenance service as described in Special Condition 8	(N)
	(N)		(N)

LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS*	Per Lamp Per Month			
			All Classes		Half-Hour Adjustment	
INCANDESCENT LAMPS:						
58	20	600	TBD	(N)	TBD	(R)
92	31	1,000	TBD		TBD	
189	65	2,500	TBD		TBD	
295	101	4,000 **	TBD		TBD	
405	139	6,000 **	TBD		TBD	
620	212	10,000 **	TBD		TBD	
860	294	15,000 **	TBD		TBD	
MERCURY VAPOR LAMPS:						
40	18	1,300	TBD		TBD	
50	22	1,650	TBD		TBD	
100	40	3,500	TBD		TBD	
175	68	7,500	TBD		TBD	
250	97	11,000	TBD		TBD	
400	152	21,000	TBD		TBD	
700	266	37,000	TBD		TBD	
1,000	377	57,000	TBD		TBD	
LIGHT EMITTING DIODE (LED) LAMPS: 120 VOLTS						
42	14	837	TBD	(N)	TBD	(R)

* Latest published information should be consulted on best available lumens.
 ** Service for incandescent lamps over 2,500 lumens will be closed to new installations after September 11, 1978.
 *** Closed to new installations and new lamps on existing circuits, see condition 8A.

(Continued)



SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES: (Cont'd.)

HIGH PRESSURE SODIUM VAPOR LAMPS AT:				(N)		(R)
120 VOLTS						
35	15	2,150	TBD		TBD	
50	21	3,800	TBD		TBD	
70	29	5,800	TBD		TBD	
100	41	9,500	TBD		TBD	
150	60	16,000	TBD		TBD	
200	80	22,000	TBD		TBD	
HIGH PRESSURE SODIUM VAPOR LAMPS AT:						
240 VOLTS						
50	24	3,800	TBD		TBD	
70	34	5,800	TBD		TBD	
100	47	9,500	TBD		TBD	
150	69	16,000	TBD		TBD	
200	81	22,000	TBD		TBD	
250	100	25,500	TBD		TBD	
310	119	37,000	TBD		TBD	
360	144	45,000	TBD		TBD	
400	154	46,000	TBD		TBD	
LOW PRESSURE SODIUM VAPOR LAMPS:						
35	21	4,800	TBD		TBD	
55	29	8,000	TBD		TBD	
90	45	13,500	TBD		TBD	
135	62	21,500	TBD		TBD	
180	78	33,000	TBD		TBD	
METAL HALIDE LAMPS:						
70	30	5,500	TBD		TBD	
100	41	8,500	TBD		TBD	
150	63	13,500	TBD		TBD	
175	72	14,000	TBD		TBD	
250	105	20,500	TBD		TBD	
400	162	30,000	TBD		TBD	
1,000	387	90,000	TBD		TBD	
INDUCTION LAMPS:						
55	19	3,000	TBD		TBD	
85	30	4,800	TBD		TBD	
165	58	12,000	TBD	(N)	TBD	(R)

Ballast Factors by Lamp Type and Wattage Range (N)

<u>Watt Range</u>	<u>Ballast Factor</u>	(N)	<u>Watt Range</u>	<u>Ballast Factor</u>	(N)
<u>MERCURY VAPOR</u>			<u>HIGH PRESSURE SODIUM VAPOR</u>		
1 to 75	31.00%	(N)	<u>120 Volts</u>		
76 to 125	17.07%		40 to 60	25.44%	(N)
126 to 325	13.69%		61 to 85	21.25%	
326 to 800	11.22%		86 to 125	20.00%	
801 +	10.34%		126 +	17.07%	
<u>LOW PRESSURE SODIUM VAPOR</u>			<u>120 Volts</u>		
1 to 40	75.61%				
41 to 75	54.32%				

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76	to	110	46.34%		1	to	60	40.49%	
111	to	160	34.42%		61	to	85	42.16%	
161	+		26.83%		86	to	125	37.56%	
<u>METAL HALIDE</u>					126	to	175	34.63%	
0	to	85	25.44%		176	to	225	18.54%	
86	to	200	20.39%		226	to	280	17.07%	
201	to	375	22.93%		281	to	380	12.35%	
376	to	700	18.54%		381	+		12.68%	(N)
701	+		13.27%	(N)					

(Continued)

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SCHEDULE LS-2-CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

RATES:
(Cont'd.)

TOTAL ENERGY RATES

Total Energy Charge Rate (\$ per kWh) TBD (T)

UNBUNDLING OF TOTAL ENERGY CHARGES

The total energy charge is unbundled according to the component rates shown below.

Energy Rate by Components (\$ per kWh)

Generation	TBD	(T)
Distribution	TBD	-
Transmission*	TBD	-
Transmission Rate Adjustments*	TBD	-
Reliability Services*	TBD	-
Public Purpose Programs	TBD	-
Nuclear Decommissioning	TBD	-
Competition Transition Charge	TBD	-
Energy Cost Recovery Amount	TBD	-
DWR Bond	TBD	(T)

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)



SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:

1. **TYPE OF SERVICE:** This schedule is applicable to multiple lighting systems to which PG&E will deliver current at secondary voltage. Multiple current will normally be supplied at 120/240 Volt, single-phase. In certain localities PG&E may supply service from 120/208 Volt, wye-systems, polyphase lines in place of 240 Volt service. Unless otherwise agreed, existing series current will be delivered at 6.6 amperes. Single-phase service from 480 Volt sources and series circuits will be available in certain areas at the option of PG&E when this type of service is practical from PG&E's engineering standpoint. All currents and voltages stated herein are nominal, reasonable variations being permitted.

New lights will normally be supplied as multiple systems. Series service to new lights will be made only when it is practical from PG&E's engineering standpoint to supply them from existing series systems.

2. **SERVICE REQUIREMENTS**

a) **PHOTO CONTROLS**

This rate schedule is predicated on an electronic type photo controls meeting ANSI standard C136.10, with a turn on value of 1.0 foot-candles and a turn-off value of 1.5 foot-candles. Electro-mechanical or thermal type photo controls are not acceptable for this rate schedule.

b) **LIGHT OR POLE NUMBERING**

As agreed upon by the parties, pole number sequencing and coding for single lights or multiple lights on a single pole, shall be provided by either party and must conform to PG&E's billing system. Customer will provide physical numbering on lights or poles for LS-2 installations in order to facilitate accurate billing and inventory reporting. Numbering is required prior to energizing facilities. Numbering must be legible from the ground.

c) **SERVICE REQUESTS**

Service request shall include form 72-1007 for installation and energizing, and form 72-1008 for removing or de-energizing Customer's facilities.

(Continued)



SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

4. **NON REFUNDABLE PAYMENT FOR SERVICE INSTALLATION**

- a) Customer or Applicant shall pay in advance the estimated installed cost necessary to establish a service delivery point. A one-time revenue allowance will be provided based on Customer's kWh usage and the distribution component of the energy rate posted in the Rate Schedule for the lamps installed. The total allowance shall be determined by taking the annual equivalent kWh times the Distribution component of this rate divided by the cost of service factor shown in Electric Rule 15.C.
- b) The allowance will only be provided where PG&E must install capital assets to connect load. No allowance will be provided where a simple connection is required. Only lights on a minimum 11 hour All Night (AN) schedule for permanent service shall be granted an allowance. Where Applicant received allowances based upon 11 hour AN operation, no billing adjustments, as otherwise provided for in Special Condition 7, shall be made for the first three (3) years following commencement of service.

Line or service extensions in excess of the above shall be installed under Special Condition 9.

5. **TEMPORARY SERVICE:** Temporary services will be installed under electric Rule 13.

6. **ANNUAL OPERATING SCHEDULES:** The above rates for AN service assume 11 hours operation per night and apply to lamps which will be turned on and off once each night in accordance with a regular operating schedule selected by the Customer but not exceeding 4,100 hours per year.

(Continued)



SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

7. **OPERATING SCHEDULES OTHER THAN ALL-NIGHT:** Rates for regular operating schedules other than full all-night will be the AN rate, plus or minus, respectively, the half-hour adjustment for each half-hour more or less than an average of 11 hours per night. This adjustment will apply only to lamps on regular operating schedules of not less than 1,095 hours per year, or 3 hours per night, and may be applied for 24 hour operation. Photo control devices used for more or less than AN must be approved by PG&E prior to adjustments in billing. (T)

8. **MAINTENANCE, ACCESS, CLEARANCES**

a) Maintenance

The Class B and C rates include all labor and material necessary for the inspection, cleaning, or replacement by PG&E of lamps and glassware. Replacement is limited to certain glassware such as is commonly used and manufactured in reasonably large quantities. A commensurate extra charge will be made for maintenance of glassware of a type entailing unusual expense. The Class C rate also includes all labor and material necessary for replacement by PG&E of photoelectric controls. Class B and C rates are closed to new installations and to additional lamps in existing accounts as of March 1, 2006.

b) Under the grand fathered Class B and C rates, the following shall apply:

- 1) At Customer's request, where PG&E's resources permit, PG&E will paint poles for Customer on a time and material basis. This service will only be offered for poles that have been designed to be painted.
- 2) PG&E will isolate any trouble in the Customer's system which has resulted in an outage or diminished light output.
- 3) PG&E will make necessary repairs which do not require wiring replacement on accessible wiring between poles and on equipment and wiring in and on poles to keep the system in operating condition.
- 4) PG&E will provide labor for the replacement of material such as ballasts, relays, fixtures, individual cable runs between poles where such runs are in conduit, and other individual parts of the system that are not capital items.
- 5) Customer shall compensate PG&E for any material furnished by PG&E not included in 8.A. above. The exception for Class B is that photo control replacement is not included in the rate. Customer must have been on Class C for this service.
- 6) PG&E shall not be responsible for excavation or any major replacement of circuits, conduits, poles, or fixtures owned by the Customer.
- 7) Tree trimming is the responsibility of the Customer for installation of new lights or for maintaining lighting patterns of existing lights.

(Continued)



SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

8. **MAINTENANCE, ACCESS, CLEARANCES** (Cont'd.)

c) Access

Customer will maintain adequate access for PG&E's standard equipment used in maintaining facilities and for installation of its facilities. PG&E reserves the right to collect additional maintenance costs due to obstructed access or other conditions preventing PG&E from maintaining its equipment with standard operating procedures. Applicant or Customer shall be responsible for rearrangement charges as provided for in Special Condition 3.e.

d) Clearances

Customer applicant shall, at its expense, correct all access or clearance infractions, or pay PG&E its total estimated cost for PG&E to relocate facilities to a new location which is acceptable to PG&E. Failure to comply with corrective measures within a reasonable time may result in discontinuance of service in accordance with electric Rule 11. Applicant or Customer shall be responsible for tree trimming to maintain lighting patterns of existing lights.

(Continued)

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SCHEDULE LS-2—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

13. **BILLING:** This Rate Schedule is subject to PG&E's other rules governing billing issues, as may be applicable. PG&E performs regular auditing as part of this rate schedule.

(N)
(D)

Bundled Service Customers receive supply and delivery service solely from PG&E. The Customer's bill is based on the Total Rate set forth above.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, the FTA (where applicable), the RRBMA (where applicable), the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, the FTA (where applicable), the RRBMA (where applicable), the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

	<u>DA CRS</u>	<u>CCA CRS</u>	
Energy Cost Recovery Amount Charge (per kWh)	TBD	TBD	(T)
Power Charge Indifference Adjustment (per kWh)	TBD	TBD	
DWR Bond Charge (per kWh)	TBD	TBD	
CTC Charge (per kWh)	TBD	TBD	
Total CRS (per kWh)	TBD	TBD	(T)

14. **DWR BOND CHARGE:** The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts.

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT

EXHIBIT E

Electric Rate Schedule LS-3



SCHEDULE LS-3—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE

APPLICABILITY: Applicable to service to electrolier lighting systems, excluding incandescent luminaires, which illuminate streets, highways, and other outdoor ways and places where the Customer owns the lighting fixtures, poles and interconnecting circuits, and PG&E furnishes metered energy. Customers may connect incidental load on a single service account, not to exceed 5% of Customer's total circuit load on the account. Total lighting load must operate in conformance with the 85% off-peak design of this Rate. Architectural or landscape lighting for publicly dedicated outdoor ways and places is allowed under this schedule. All lighting must be power factor corrected in accordance with electric Rule 2G. Where loads are found outside these limits PG&E will default the rate to A1 General Service. (T)
(N)
(N)

TERRITORY: The entire territory served.

RATES: Total bundled service charges are calculated using the total rates shown below. Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

TOTAL RATES

Total Customer Charge (\$ per meter per day)	\$0.19713 (I)	
Total Energy Rate (\$ per kWh)	TBD	(T)

UNBUNDLING OF TOTAL RATES

Total bundled service charges shown on Customers' bills are unbundled according to the component rates shown below.

Customer Charge Rates: Customer charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.

Energy Rate by Components (\$ per kWh)

Generation	TBD	(T)
Distribution	TBD	
Transmission*	TBD	
Transmission Rate Adjustments*	TBD	
Reliability Services*	TBD	
Public Purpose Programs	TBD	
Nuclear Decommissioning	TBD	
Competition Transition Charge	TBD	
Energy Cost Recovery Amount	TBD	
DWR Bond	TBD	(T)

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)



SCHEDULE LS-3—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE
(Continued)

SPECIAL
CONDITIONS:

1. **TYPE OF SERVICE:** This schedule is applicable to multiple lighting systems to which PG&E will deliver current at a) secondary voltage and b) to series street lighting systems for which PG&E will furnish constant current regulating transformers. Service to series systems through PG&E-furnished constant current regulating transformers is closed to new installations. Multiple current will normally be supplied at 120/240 Volts, single-phase. (In certain localities PG&E supplies service from 120/208 Volt, wye-systems, polyphase lines in place of 240 Volt service.) Unless otherwise agreed, existing series current will be delivered at 6.6 amperes. Single-phase service from 480 volt sources will be available in certain areas at the option of PG&E when this type of service is practical from PG&E's engineering standpoint. All currents and voltages stated herein are nominal, reasonable variations being permitted.

New lights will normally be supplied as multiple systems. Series service to new lights will be made only when it is practical from PG&E's engineering standpoint to supply them from existing series systems.

2. **SERVICE CONNECTIONS**

OVERHEAD: In an overhead area a single drop will be installed to the Customer owned pole where such pole meets permanent service pole requirements. For an overhead to underground system, service will be established from a riser to the Customer's appropriate termination facility described below.

UNDERGROUND: In an underground area, service will be established at the nearest existing secondary box. Where no secondary facilities exist, a new service delivery point, transformer and secondary splice box, as required, will be installed in the shortest, most practical configuration from the connection on the distribution line source.

GENERAL

- a) PG&E may, at its option, establish service to Customer's meter pedestal where (1) that pedestal meets all safety requirements under PG&E's design requirements for meter locations, and other tariff requirements of PG&E; (2) the pedestal is adjacent to readily available secondary facilities; and (3) no line extension is required. PG&E may at its option, agree to terminate in a Customer-owned box only when it is immediately adjacent to the pedestal.
- b) Where the Customer chooses to own the service wire and conduit from its termination point to the service delivery point on PG&E's secondary distribution system, PG&E will establish service delivery points in close proximity to its distribution system. No additional junction boxes may be placed between the service delivery point and the Customer's termination point.

(Continued)



SCHEDULE LS-3—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

2. **SERVICE CONNECTIONS** (Cont'd.)

GENERAL (Cont'd.)

- c) Line extensions shall be installed as provided in Special Condition 6.
- d) The Customer or Applicant shall pay, in advance, PG&E's estimated cost for any relocation, or rearrangement of PG&E's existing street light or service facilities if requested by Customer or Applicant and agreed to by PG&E.
- e) **Customer Installation Responsibility:** Customer shall install, own and maintain all facilities beyond the service delivery point. For PG&E's serving facilities, Customer or Applicant, at its expense, shall perform all necessary trenching, backfill and paving, and shall furnish and install all necessary conduit and substructures, (including substructures for transformer installations if necessary for street lights only) in accordance with PG&E's specifications. Riser material will be installed by PG&E at the Customer's expense. Upon acceptance by PG&E, ownership of the conduit and substructures shall vest in PG&E. Customer will provide rights of way as provided in electric Rule 16. Customer will attach sufficient labeling to facilities to indicate metered lighting.
- f) **PG&E Installation Responsibility:** PG&E shall furnish and install the underground or overhead service conductor, transformers and necessary facilities to complete the service to the distribution line source subject to the payment provisions of Special Condition 3. Only duly authorized employees of PG&E shall connect Customer's loads to, or disconnect the same from, PG&E's electrical distribution facilities.
- g) Temporary services will be installed under the provisions of electric Rule 13.

(N)
(N)

3. **NON REFUNDABLE PAYMENT FOR SERVICE POINT INSTALLATION**

The Applicant shall pay in advance the estimated installed cost minus a one-time average revenue allowance. Annually, PG&E will determine a fixed average allowance by taking the average annual equivalent kWh for the class multiplied by the distribution component of the energy rate, then divided by the cost of service factor shown in electric Rule 15.C

(N)
|
|
(N)
(D)

4. **METERING:** Each point of delivery to an electrolier circuit or circuits will be metered and billed separately.

(Continued)



SCHEDULE LS-3—CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

7. **BILLING:** A customer's bill is calculated based on the option applicable to the customer.

Bundled Service Customers receive supply and delivery service solely from PG&E. The customer's bill is based on the Total Rates and Conditions set forth in this schedule.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, the FTA (where applicable), the RRBMA (where applicable), the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, the FTA (where applicable), the RRBMA (where applicable), the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

	DA CRS	CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	TBD	TBD	(T)
Power Charge Indifference Adjustment (per kWh)	TBD	TBD	
DWR Bond Charge (per kWh)	TBD	TBD	
CTC Charge (per kWh)	TBD	TBD	
Total CRS (per kWh)	TBD	TBD	(T)

8. **DWR BOND CHARGE:** The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts.

STREETLIGHT RATE DESIGN SETTLEMENT AGREEMENT

EXHIBIT F

Electric Rate Schedule TC-1



SCHEDULE TC-1—TRAFFIC CONTROL SERVICE

APPLICABILITY: Applicable to metered service for traffic control related equipment operating on a 24-hour basis, owned by governmental agencies and located on streets, highways and other publicly-dedicated outdoor ways and places. Streetlights on traffic circuits and other equipment operating on a 24-hour basis in conformity with this rate design, may also be connected under this Schedule. Also applicable for service to these installations where service is initially established in the name of a developer who has installed such systems as required by a governmental agency, where ownership of facilities and responsibility for service will ultimately be transferred to the jurisdiction requiring the installation. Non-conforming incidental load such as low voltage sprinkler controls may also be attached where such loads do not exceed 5% of the total connected load served under a TC-1 Service Account. Maximum load per meter is 34,000 kWh per month. (T) (D)
(N)
(N)
(N)
(N)

TERRITORY: The entire territory served.

RATES: Total bundled service charges are calculated using the total rates shown below. Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

TOTAL RATES

Customer Charge Rate (\$ per meter per day)	TBD	(T)
Energy Rate (\$ per kWh)	TBD	(T)

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below.

UNBUNDLING OF TOTAL RATES

Customer Charge Rates: Customer charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.

Energy Rate by Components (\$ per kWh)

Generation	TBD	(T)
Distribution	TBD	
Transmission*	TBD	
Transmission Rate Adjustments*	TBD	
Reliability Services*	TBD	
Public Purpose Programs	TBD	
Nuclear Decommissioning	TBD	
Competition Transition Charge	TBD	
Energy Cost Recovery Amount	TBD	(T)
DWR Bond		

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)



SCHEDULE TC-1—TRAFFIC CONTROL SERVICE
(Continued)

SPECIAL
CONDITIONS:

1. **TYPE OF SERVICE:** Energy will normally be supplied at 120/240 Volt single-phase service (120/208 volts wye-systems in certain localities). Single-phase service from 480 Volt sources will be available in certain areas at the option of PG&E when this type of service is practical from PG&E's engineering standpoint.

2. **SERVICE CONNECTIONS**

OVERHEAD: In an overhead area a single drop will be installed to the Customer - owned pole where such pole meets permanent service pole requirements. For an overhead to underground system service will be established from a riser to the Customer's appropriate termination facility as described below.

UNDERGROUND: In an underground area, service will be established at the nearest existing secondary box. Where no secondary facilities exist, a new service delivery point, transformer and secondary splice box, as required, will be installed in the shortest, most practical configuration from the connection on the distribution line source.

GENERAL

- a) PG&E may, at its option, establish service to Customer's meter pedestal where 1) that pedestal meets all safety requirements under PG&E's design requirements for meter locations, and other tariff requirements of PG&E; 2) the pedestal is adjacent to readily available secondary facilities; and 3) no line extension is required. PG&E may at its option, agree to terminate in a Customer owned box only when it is immediately adjacent to the pedestal.
- b) Where the Customer chooses to own the service wire and conduit from its termination point to the service delivery point on PG&E's secondary distribution system, PG&E will establish service delivery points in close proximity to its distribution system. No additional junction boxes may be placed between the service delivery point and the Customer's termination point.
- c) Line extensions shall be installed as provided in special condition 6.
- d) Customer or Applicant shall pay, in advance, PG&E's estimated cost for any relocation, or rearrangement of PG&E's existing street light or service facilities if requested by Customer or Applicant and agreed to by PG&E.
- e) **Customer Installation Responsibility:** Customer or Applicant shall install, own and maintain all facilities beyond the service delivery point. For PG&E's serving facilities, Customer or Applicant shall, at its expense, perform all necessary trenching, backfill and paving, and shall furnish and install all necessary conduit, substructures (including substructures for transformer installations if necessary) in accordance with PG&E's specifications. Riser material will be installed by PG&E at the Customer's or Applicant's expense. Upon acceptance by PG&E, ownership of the conduit and substructures shall vest in PG&E. Customer or Applicant shall provide rights of way consistent with the provisions of electric Rule 16.

(Continued)



SCHEDULE TC-1—TRAFFIC CONTROL SERVICE
(Continued)

SPECIAL
CONDITIONS:
(Cont'd.)

8. **BILLING:** A Customer's bill is calculated based on the option applicable to the Customer. Payment will be made in accordance with PG&E's filed tariffs.

Bundled Service Customers receive supply and delivery services solely from PG&E. The customer's bill is based on the Total Rates and Conditions set forth in this schedule.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, the FTA (where applicable), the RRBMA (where applicable), the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, the FTA (where applicable), the RRBMA (where applicable), the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

	<u>DA CRS</u>	<u>CCA CRS</u>	
Energy Cost Recovery Amount Charge (per kWh)	TBD	TBD	(T)
Power Charge Indifference Adjustment (per kWh)	TBD	TBD	
DWR Bond Charge (per kWh)	TBD	TBD	
CTC Charge (per kWh)	TBD	TBD	
Total CRS (per kWh)	TBD	TBD	(T)

9. **DWR BOND CHARGE:** The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts.



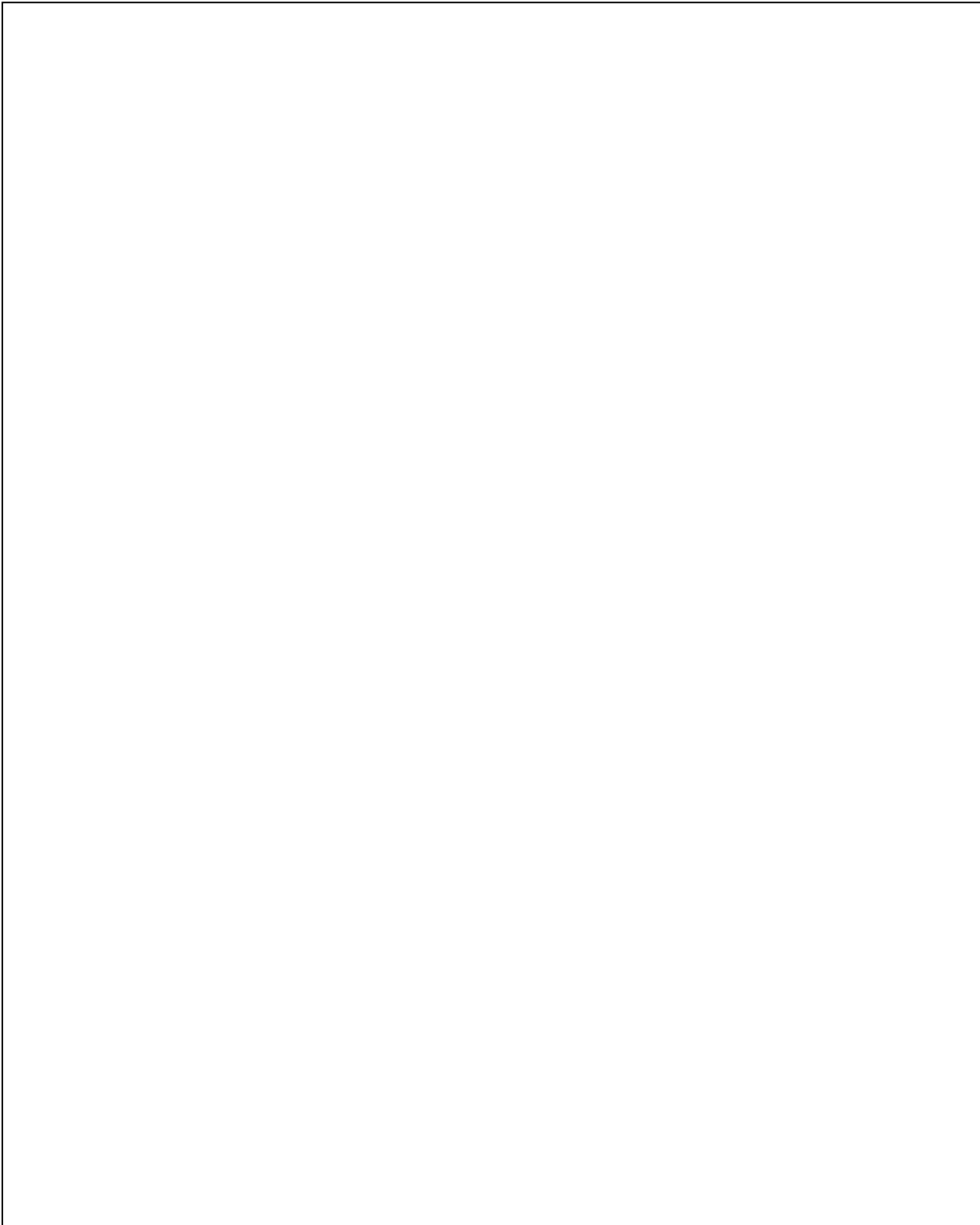
Pacific Gas and Electric Company
San Francisco, California

Canceling

Revised
Revised

Cal. P.U.C. Sheet No.
Cal. P.U.C. Sheet No.

DRAFT
25831-E



Advice Letter No.
Decision No.

Issued by
Brian K. Cherry
Vice President
Regulatory Relations

Date Filed _____
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ATTACHMENT 3
SUPPLEMENTAL SETTLEMENT AGREEMENT
ON MEDIUM AND LARGE LIGHT AND POWER RATE DESIGN ISSUES

**SUPPLEMENTAL SETTLEMENT AGREEMENT ON
MEDIUM AND LARGE LIGHT AND POWER RATE DESIGN ISSUES
IN PG&E'S APPLICATION 06-03-005**

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), the parties to this Medium and Large Light and Power (MLLP) Rate Design Settlement Agreement (Settling Parties, MLLP Settlement) agree on a mutually acceptable outcome to the MLLP rate design issues in Application (A.) 06-03-005, Application Of Pacific Gas And Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, And Rate Design. This MLLP Settlement is supplemental to the Settlement in A. 06-03-005 filed in this proceeding on February 9, 2007 (February 9 Settlement), in that it uses the revenue allocation agreed to in the February 9 Settlement and addresses MLLP issues that were not resolved in the February 9 Settlement. The Settling Parties intend that the complementary outcomes of this MLLP Settlement and the February 9 Settlement be consolidated in the Commission's final decision in this proceeding. The details of this MLLP Settlement are set forth herein.

II. MLLP SETTLING PARTIES

The MLLP Settling Parties are as follows:

- Building Owners and Managers Associations of San Francisco and of California (BOMA)
- California Large Energy Consumers Association (CLECA)
- California League of Food Processors (CLFP)
- California Manufacturers & Technology Association (CMTA)
- California Retailers Association (CRA)
- Cogeneration Association of California (CAC)

- Direct Access Customer Coalition (DACC)
- Energy Producers and Users Coalition (EPUC)
- Energy Users Forum (EUF)
- Federal Executive Agencies (FEA)
- Indicated Commercial Parties (ICP)
- Pacific Gas and Electric Company (PG&E)

III. MLLP SETTLEMENT CONDITIONS

This MLLP Settlement resolves the issues raised by the Settling Parties in A.06-03-005 on MLLP rate design, subject to the conditions set forth below:

1. This MLLP Settlement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters. This MLLP Settlement builds on the underlying marginal cost and revenue allocation in the February 9 Settlement and incorporates that agreement by reference.
2. This MLLP Settlement represents a compromise among the Settling Parties' respective litigation positions, not agreement to or endorsement of disputed facts and law presented by the Settling Parties in this proceeding. This MLLP Settlement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.
3. The Settling Parties agree that this MLLP Settlement is reasonable in light of the testimony submitted, consistent with law, and in the public interest.
4. The Settling Parties agree that no provision of this MLLP Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
5. This MLLP Settlement may be amended or changed only by a written agreement

signed by the Settling Parties.

6. The Settling Parties shall jointly request Commission approval of this MLLP Settlement and shall actively support its prompt approval. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The Settling Parties intend the MLLP Settlement to be interpreted and treated as a unified, integrated agreement incorporating the February 9 Settlement, which forms the foundation for the MLLP rate design agreed to herein. In the event the Commission rejects or modifies this MLLP Settlement or the underlying February 9 Settlement, the Settling Parties reserve their rights under CPUC Rule 12.4.

IV. SETTLEMENT HISTORY

In its Test Year 2007 General Rate Case (GRC) Application 05-12-002, PG&E proposed that the proceeding be separated into two distinct phases: Phase 1, which would cover the revenue requirement testimony submitted with that application, and Phase 2, which would cover electric marginal costs, revenue allocation, and rate design. The Assigned Commissioner's Ruling and Scoping Memo in A.05-12-002 directed PG&E to file its marginal costs, revenue allocation, and rate design proposals as a new application rather than as a separate phase.

Consistent with the Assigned Commissioner's Ruling in A.05-12-022, PG&E filed Application 06-03-005 on March 2, 2006, related to electric marginal costs, revenue allocation, and rate design. According to its application, PG&E's marginal cost, revenue allocation and rate design proposals were intended to "continue progress toward cost based, efficient pricing, while taking into consideration equity among customers and customer acceptance." The application was protested on March 27, 2006, by DRA.

A prehearing conference was held in the proceeding on May 3, 2006 before Administrative Law Judge (ALJ) Fukutome and Assigned Commissioner Rachelle Chong. The scope of the proceeding and procedural schedule were set forth in the Assigned Commissioner's Ruling and Scoping Memo dated May 25. In compliance with the Scoping Memo, PG&E updated its showing on June 26. DRA served prepared testimony on September 13. Intervenors AECA, BOMA, CAC, CAL-SLA, CFBF, CLECA, CLFP, CMTA-ICP, DACC, EPUC, FEA, PV Now, TURN, Vote Solar, and WMA served their prepared testimony on October 27.

Meanwhile, on September 20, PG&E held a meet and confer session with all parties as well as Commission staff, as directed in the Scoping Memo. After providing notice pursuant to Rule 12.1(b), PG&E conducted additional settlement discussions pursuant to Article 12 of the CPUC's rules with the active parties to the proceeding. On November 1, PG&E held a mandatory settlement conference pursuant to the Scoping Memo. Based on the settlement discussions, PG&E and the Settling Parties sought extensions of the procedural schedule, which were granted by ALJ Rulings dated November 9 and December 14, 2006.

On January 4, 2007, parties to the settlement discussions reached agreement in principle on the terms of a Settlement Agreement respecting electric marginal costs and revenue allocation. The following day, PG&E's counsel notified ALJ Fukutome that the active parties to the proceeding had reached settlement in principle regarding those issues and requested a further extension of the procedural schedule to memorialize that settlement and continue their efforts to reach agreement on rate design issues. ALJ Fukutome granted the request by written ruling dated January 10, 2007. In that ruling ALJ Fukutome allowed the parties until March 16, 2007, in which to file a settlement of rate design issues. On February 9, 2007, 22 parties filed a Settlement Agreement respecting marginal costs and revenue allocation (February 9 Settlement). They stated that discussions would continue in an effort to reach agreement on rate design issues.

After several discussions, on March 5, 2007 parties to this MLLP Settlement reached a final agreement in principle, building from the revenue allocation agreed to in the February 9 Settlement.

V. MLLP SETTLEMENT TERMS GENERALLY

The Settling Parties agree that the primary purpose of rate design for the MLLP classes is to take the revenue allocations reached for those classes in the February 9 Settlement and ensure that they are fully recovered through MLLP rates in a manner that is just and reasonable, is in the public interest, is reasonably based on the marginal costs from the February 9 Settlement, and reflects a reasonable compromise of Settling Parties' proposals. The Settling Parties agree that the illustrative rates set forth herein are consistent with the revenue allocation set forth in Table 5 of the February 9 Settlement, which was based on estimated March 1, 2007 effective rates. The Settling Parties agree that the actual rates derived pursuant to this MLLP Settlement shall be designed on an overall revenue-neutral basis to collect the then-current revenue allocated to the MLLP classes and will differ from the rates presented herein. However, these actual rates shall be based on the rate design methods described below.

Illustrative rates for Schedules A-10, A-10 TOU, E-19, E-20, and Standby are set forth in Exhibit A to this MLLP Settlement. The terms of this Settlement Agreement for Standby Service are reflected in draft tariffs, as appropriate, and pro forma standby tariff changes are attached to this MLLP Settlement as Exhibit B.

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

Parties further agree that this MLLP Settlement resolves all MLLP rate design issues in A.06-03-005.

VI. MLLP RATE DESIGN SETTLEMENT TERMS

The Settling Parties agree that rates to collect the revenue allocated to the MLLP customer classes under the February 9 Settlement shall be designed as set forth below, including the voltage-level intra-class allocations for Schedule A-10 and standby service Schedule S as reflected in Exhibit A (which were not fully specified in the February 9 Settlement), and that these rates shall serve as a starting point for determining the changes to rates necessary to collect the adopted revenue requirement in effect when this Settlement is implemented.

1. Illustrative Settlement Rates

Illustrative settlement rates for the MLLP rate schedules are presented in Exhibit A. The rates were developed to collect the revenue allocated to the MLLP customer classes set forth in Tables 5-A and 5-B of the February 9 Settlement based on estimated March 2007 revenue requirements. Adopted revenue requirements in effect upon settlement implementation shall be applied to determine initial settlement rates. Therefore, the actual rates will vary from those shown in Exhibit A when the Phase 2 rate changes are implemented.

2. Methods Used To Develop Illustrative Settlement Rates

The Settling Parties agree that the basic rate designs for each of the applicable MLLP rate schedules will be updated upon settlement implementation using the methods underlying development of the illustrative settlement rates for Schedules A-10, A-10 TOU, E-19, E-20, and Standby presented in Exhibit A. These methods reflect

approaches proposed by PG&E in its Rate Update testimony, Exhibit (PG&E-4), filed June 26, 2006, as updated to incorporate the revenue allocation proposals and updated costs agreed upon in the February 9 Settlement. The Settling Parties have agreed to one additional modification of PG&E's MLLP proposals which is intended to ensure that total bundled service volumetric rates by TOU period under Schedules E-19 and E-20 will vary at least in proportion to the variation in PG&E's marginal energy costs. For service at transmission and primary distribution service voltages, this will involve setting Schedule E-19 and E-20 TOU generation energy charges residually, in such a way that the combined sum of generation energy charges and those non-bypassable charges that do not vary by TOU period vary in direct proportion to the TOU profile established by the settlement generation energy marginal costs. (This change affects bundled service rates under Schedules E-19 and E-20 but not Direct Access rates, because Direct Access customers do not pay generation energy charges.) This modification is not needed for the rates applicable to service at secondary distribution voltages under Schedules E-19 and E-20, because the volumetric rates for secondary voltage service include significant shares of both generation and distribution marginal capacity cost revenue in addition to marginal energy cost revenue, so these rates already vary in significantly greater proportion than do the underlying marginal generation energy costs. Distribution component demand and energy charge principles are based upon PG&E's filed proposals, as updated to reflect marginal costs from the February 9 Settlement. Where applicable (affecting a small number of Schedule A-10 and E-19V customers with historic demand levels of less than 20 kW), any FTA or RRBMA adjustments would then apply additively to establish total energy charges. The specific principle and

methodology used to reshape the sum of generation energy charges and non-bypassable charges (for transmission and primary distribution service voltage volumetric rates by TOU period under Schedules E-19 and E-20) is to be utilized only upon initial settlement implementation, with subsequent component rate design changes between General Rate Cases governed by Term VII.3.(G) of the February 9 Settlement.

3. Adopt Revised Customer Charges

The Settling Parties agree that PG&E's proposed customer charges for the MLLP rate schedules are reasonable. The Settling Parties agree further that it is reasonable for the ongoing monthly TOU meter charges currently applicable for customers taking voluntary TOU service under Schedules E-19V and A-10 TOU to no longer be applied, at such time as the customer's existing TOU meter is replaced as part of the Advanced Meter Infrastructure (AMI) Project, pursuant to D. 06-07-027, and the new meter is activated and used for billing.

4. Rate Limiters for Schedules E-19 and E-20

The Settling Parties agree that it is reasonable to slightly reduce the protection provided by summer season average rate limiters for Schedules E-19 and E-20. Summer season average rate limiters will continue to be applicable for Schedule E-19 and E-20 customers taking service at secondary and primary distribution voltages, at the revised levels set forth in Exhibit A. The summer season average rate limiter will be based on a 26 percent load factor, rather than 32 percent as in current rates, for the duration of the 2007 GRC Phase 2 cycle, and will be considered for being eliminated entirely in PG&E's next GRC Phase 2 proceeding. The revised summer season

average rate limiters would apply as caps on total amounts billed for bundled service usage, exclusive of customer charges, and thus provide summer-season bill protection comparable to but slightly less than those provided by the current average rate limiters. The Settling Parties understand that, consistent with past practice, the final rates upon implementation should incorporate adjustments to account for estimated undercollections associated with the average rate limiter.

5. Adopt Updated Standby Service Rates

The Settling Parties agree that PG&E's proposed methods for setting standby service rates as modified to reflect provisions of the February 9 Settlement and by the terms of this agreement produce rates that are just and reasonable, are in the public interest, and reflect a rational compromise of Settling Parties' original proposals. The Settling Parties understand that any rate changes adopted by the Federal Energy Regulatory Commission (FERC) for those rate elements over which FERC has jurisdiction will be passed through according to FERC rules. The Settling Parties also agree to modify certain terms and conditions of standby service, primarily as they relate to how standby contract demand levels are established, how reactive demand charges are administered and billed under Schedule S, and the applicable reactive demand charge rate, all as set forth in the pro forma tariff language in Exhibit B.

6. Provisions Related to Standard Non-Firm Service Rates

All parties to the February 9, 2007 Settlement have already agreed in Term VII.1. (G) that all non-firm customers will transfer to Base Interruptible Program Schedule E-BIP on or before January 1, 2008, and that the demand and energy charge incentives for service under the standard non-firm rate program should be converted to Schedule

E-BIP incentives and retained at the same absolute level of demand charge credits as are currently in effect for Schedule E-BIP service under Schedules A-10, E-19 and E-20. Thus, the Schedule E-BIP discounts in 2008 and subsequent years will be equal to the 2007 Schedule E-BIP discounts for Option A adopted by D.06-11-049, p. 27. In D.05-04-053, the Commission established a goal of eventually moving non-firm customers to service under Schedule E-BIP, with the understanding that Schedule E-BIP incentives are meant to be comparable to those available under the original non-firm tariffs. The Settling Parties agree that this settlement meets that objective.

7. Non-Firm Service and Demand Bidding Program Enrollment

The Settling Parties agree that it is reasonable for the terms of service under the Base Interruptible Program (Schedule E-BIP) to be modified so as to provide for E-BIP customers to also be automatically enrolled under Schedule E-DBP, PG&E's Demand Bidding Program. (Existing tariff provisions already allow for voluntary enrollment of non-firm service customers under the DBP, and preclude "dual payment," meaning that customers do not receive additional DBP incentive payments for load reductions on days that the interruptible programs are called upon.) This change should promote additional participation in the DBP from a group of customers whose operations are already particularly well-situated for demand response load reductions. Moreover, because customer participation in each DBP event is always voluntary, this change will not impose any new costs or obligations on the affected customers.

8. Franchise Fee Surcharge

The Settling Parties agree that PG&E's proposal to revise the franchise fee surcharge calculation for direct access and community choice aggregation customers,

as set forth in Exhibit (PG&E-3), pages 1-15 to 1-16, is reasonable and should be adopted.

9. Timing of Structural Rate and Tariff Changes

Certain elements of this Settlement Agreement will require employee training and/or changes to PG&E systems beyond those required for a normal change in rate value. These changes include modifications to how the standby service contract demand levels and reactive demand charge will be billed and administered; and the staged discontinuation of voluntary TOU meter charges for Schedule E-19V customers as new AMI meters are installed and used for billing. These structural and system changes will be implemented by PG&E diligently as time permits in a manner consistent with smooth operations of the systems involved. The Settling Parties recognize that these changes could take several months to implement.

VII. TIMING OF RATE CHANGES

The provisions regarding the timing of this GRC rate change and rate changes between General Rate Cases agreed to in the February 9 Settlement, Term VII. 2, shall apply to this MLLP Settlement, unless specifically noted above.

VIII. SETTLEMENT EXECUTION

This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This MLLP Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the MLLP Settlement, as indicated below. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this MLLP Settlement on behalf of the Settling Parties they represent.

The undersigned represent that they are authorized to sign on behalf of the Party represented.

Building Owners and Managers Associations of
San Francisco and of California

By: _____ /s/
B.F. Roberts

Title: President, Economic Sciences Corp.

Date: 3/14/07

California Large Energy Consumers Association

By: _____ /s/
William Booth

Title: Counsel

Date: 3/13/07

California League of Food Processors

By: _____ /s/
Rob Neenan

Title: Director of Regulatory Affairs

Date: 3/13/07

California Manufacturers & Technology Association

By: _____ /s/
Keith McCrea

Title: Attorney _____

Date: 3/16/07 _____

California Retailers Association

By: _____ /s/
James Squeri

Title: Counsel _____

Date: 3/16/07 _____

Cogeneration Association of California and
Energy Producers and Users Coalition

By: _____ /s/
Nora Sheriff

Title: Counsel _____

Date: 3/16/07 _____

Direct Access Customer Coalition

By: _____ /s/
Greg Klatt

Title: Counsel _____

Date: 3/16/07 _____

Energy Users Forum

By: _____ /s/
Ann H. Kim

Title: on behalf of Carolyn Kehrein _____

Date: 3/16/07 _____

Federal Executive Agencies

By: _____ /s/
Norman Furuta

Title: Associate Counsel _____

Date: 3/15/07 _____

Indicated Commercial Parties

By: _____ /s/
Randall Keen

Title: Partner _____

Date: 3/16/07 _____

Pacific Gas and Electric Company

By: _____ /s/
Dan Pease

Title: Manager, Electric Rates _____

Date: 3/16/07 _____

EXHIBIT A

ILLUSTRATIVE MLLP SETTLEMENT RATES

SCHEDULES A-10, E-19, E-20 and STANDBY

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

A-10 Secondary
BUNDLED

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
DEMAND CHARGES (\$/kW)							
Summer							
Maximum	21,681,788	\$10.65	\$230,916,139	21,681,788	\$9.14	\$198,103,098	
Winter							
Maximum	19,737,044	\$5.33	\$105,180,168	19,737,044	\$5.33	\$105,168,331	
Revenue from Demand Charges			\$336,096,307			\$303,271,428	
Revenue from Demand as % of Total			19.03%			18.07%	
ENERGY CHARGES - Non-FTA (\$/kWh)							
Summer							
Total	6,404,230,928	\$0.12615	\$807,876,282	6,404,230,928	\$0.11921	\$763,436,991	
Winter							
Total	5,788,643,679	\$0.09556	\$553,175,139	5,788,643,679	\$0.09033	\$522,880,210	
Revenue from Energy Charges			\$1,361,051,420			\$1,286,317,201	
Revenue from Energy as % of Total			77.06%			76.64%	
CUSTOMER CHARGE (\$/meter/mo.)							
A-10	739,180	\$93	\$69,083,763	739,180	\$120	\$88,701,600	
Revenue from Customer Charges			\$69,083,763			\$88,701,600	
Revenue from Customer Chrg as % of Total			3.91%			5.29%	
			\$1,766,231,490			\$1,678,290,229	Total Rev
						-4.98%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

A-10 Primary
BUNDLED

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
DEMAND CHARGES (\$/kW)							
Summer							
Maximum	185,725	\$10.02	\$1,860,236	185,725	\$8.58	\$1,593,412	
Winter							
Maximum	177,271	\$4.82	\$854,156	177,271	\$4.90	\$868,267	
Revenue from Demand Charges			\$2,714,392			\$2,461,678	
Revenue from Demand as % of Total			17.72%			17.76%	
ENERGY CHARGES - Non-FTA (\$/kWh)							
Summer							
Total	57,183,236	\$0.12651	\$7,234,233	57,183,236	\$0.11324	\$6,475,211	
Winter							
Total	54,266,670	\$0.09512	\$5,161,974	54,266,670	\$0.08574	\$4,653,066	
Revenue from Energy Charges			\$12,396,208			\$11,128,276	
Revenue from Energy as % of Total			80.92%			80.31%	
CUSTOMER CHARGE (\$/meter/mo.)							
A-10	2,226	\$93	\$208,042	2,226	\$120	\$267,120	
Revenue from Customer Charges			\$208,042			\$267,120	
Revenue from Customer Chrg as % of Total			1.36%			1.93%	
			\$15,318,641			\$13,857,075	Total Rev
						-9.54%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

**A-10 Transmission
BUNDLED**

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue	
DEMAND CHARGES (\$/kW)							
Summer							
Maximum	7,514	\$7.01	\$52,639	7,514	\$6.33	\$47,564	
Winter							
Maximum	7,838	\$2.97	\$23,269	7,838	\$3.17	\$24,827	
Revenue from Demand Charges			\$75,908			\$72,392	
Revenue from Demand as % of Total			11.96%			13.44%	
ENERGY CHARGES - Non-FTA (\$/kWh)							
Summer							
Total	2,630,358	\$0.11902	\$313,072	2,630,358	\$0.09824	\$258,397	
Winter							
Total	2,589,834	\$0.09130	\$236,442	2,589,834	\$0.07558	\$195,728	
Revenue from Energy Charges			\$549,514			\$454,124	
Revenue from Energy as % of Total			86.57%			84.33%	
CUSTOMER CHARGE (\$/meter/mo.)							
A-10	100	\$93	\$9,346	100	\$120	\$12,000	
Revenue from Customer Charges			\$9,346			\$12,000	
Revenue from Customer Chrg as % of Total			1.47%			2.23%	
			\$634,768			\$538,516	Total Rev
						-15.16%	Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

**A-10 Secondary
TOU**

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
DEMAND CHARGES (\$/kW)						
Summer						
Maximum	21,681,788	\$10.65	\$230,916,139	21,681,788	\$9.14	\$198,103,098
Winter						
Maximum	19,737,044	\$5.33	\$105,180,168	19,737,044	\$5.33	\$105,168,331
Revenue from Demand Charges			\$336,096,307			\$303,271,428
Revenue from Demand as % of Total			19.05%			18.07%
ENERGY CHARGES (\$/kWh)						
Summer						
Peak	1,722,114,841	\$0.14554	\$250,636,154	1,722,114,841	\$0.13869	\$238,842,120
Part-Peak	1,621,311,492	\$0.13410	\$217,418,831	1,621,311,492	\$0.11951	\$193,757,746
Off-Peak	3,060,804,595	\$0.11063	\$338,620,780	3,060,804,595	\$0.10809	\$330,837,125
Winter						
Part-Peak	2,845,621,400	\$0.10413	\$296,304,519	2,845,621,400	\$0.09498	\$270,266,546
Off-Peak	2,943,022,279	\$0.08708	\$256,272,282	2,943,022,279	\$0.08583	\$252,613,664
Revenue from Energy Charges			\$1,359,252,566			\$1,286,317,201
Revenue from Energy as % of Total			77.04%			76.64%
CUSTOMER CHARGE (\$/meter/mo.)	739,180	\$93	\$69,083,763	739,180	\$120	\$88,701,600
Revenue from Customer Charges			\$69,083,763			\$88,701,600
Revenue from Customer Chrg as % of Total			3.92%			5.29%
			\$1,764,432,636			\$1,678,290,229
						-4.88%

Total Rev
Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

**A-10 Primary
TOU**

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
DEMAND CHARGES (\$/kW)						
Summer						
Maximum	185,725	\$10.02	\$1,860,236	185,725	\$8.58	\$1,593,412
Winter						
Maximum	177,271	\$4.82	\$854,156	177,271	\$4.90	\$868,267
Revenue from Demand Charges			\$2,714,392			\$2,461,678
Revenue from Demand as % of Total			17.74%			17.76%
ENERGY CHARGES (\$/kWh)						
Summer						
Peak	15,376,725	\$0.14532	\$2,234,563	15,376,725	\$0.13077	\$2,010,821
Part-Peak	14,476,654	\$0.13501	\$1,954,550	14,476,654	\$0.11371	\$1,646,133
Off-Peak	27,329,856	\$0.11103	\$3,034,538	27,329,856	\$0.10312	\$2,818,256
Winter						
Part-Peak	26,676,784	\$0.10315	\$2,751,598	26,676,784	\$0.08940	\$2,384,883
Off-Peak	27,589,886	\$0.08717	\$2,404,985	27,589,886	\$0.08221	\$2,268,182
Revenue from Energy Charges			\$12,380,234			\$11,128,276
Revenue from Energy as % of Total			80.90%			80.31%
CUSTOMER CHARGE (\$/meter/mo.)	2,226	\$93	\$208,042	2,226	\$120	\$267,120
Revenue from Customer Charges			\$208,042			\$267,120
Revenue from Customer Chrg as % of Total			1.36%			1.93%
			\$15,302,667			\$13,857,074
						-9.45%

Total Rev
Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

**A-10 Transmission
TOU**

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
DEMAND CHARGES (\$/kW)						
Summer						
Maximum	7,514	\$7.01	\$52,639	7,514	\$6.33	\$47,564
Winter						
Maximum	7,838	\$2.97	\$23,269	7,838	\$3.17	\$24,827
Revenue from Demand Charges			\$75,908			\$72,392
Revenue from Demand as % of Total			11.97%			13.44%
ENERGY CHARGES (\$/kWh)						
Summer						
Peak	707,310	\$0.13870	\$98,101	707,310	\$0.11499	\$81,333
Part-Peak	665,908	\$0.12790	\$85,168	665,908	\$0.09851	\$65,596
Off-Peak	1,257,140	\$0.10285	\$129,291	1,257,140	\$0.08867	\$111,468
Winter						
Part-Peak	1,273,128	\$0.09975	\$126,995	1,273,128	\$0.07903	\$100,620
Off-Peak	1,316,705	\$0.08292	\$109,184	1,316,705	\$0.07223	\$95,108
Revenue from Energy Charges			\$548,739			\$454,124
Revenue from Energy as % of Total			86.55%			84.33%
CUSTOMER CHARGE (\$/meter/mo.)	100	\$93	\$9,346	100	\$120	\$12,000
Revenue from Customer Charges			\$9,346			\$12,000
Revenue from Customer Chrg as % of Total			1.47%			2.23%
			\$633,992			\$538,516
						-15.06%

Total Rev
Change

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

E-19 Secondary
FIRM

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue		Billing Determinants	Rates	Revenue	
DEMAND CHARGES (\$/kW)								
Summer								
Peak	10,421,435	\$15.02	\$156,529,949		10,421,435	\$11.40	\$118,754,723	
Part-Peak	10,507,792	\$3.57	\$37,512,816		10,507,792	\$2.63	\$27,627,134	
Maximum	11,147,912	\$6.74	\$75,136,930		11,147,912	\$7.28	\$81,193,412	
Winter								
Part-Peak	9,536,989	\$1.85	\$17,643,430		9,536,989	\$1.04	\$9,956,199	
Maximum	9,691,385	\$6.74	\$65,319,938		9,691,385	\$7.28	\$70,585,112	
Revenue from Demand Charges			\$352,143,062		Revenue from Demand Charges			
Revenue from Demand as % of Total			31.16%		Revenue from Demand as % of Total			
					29.95%			
ENERGY CHARGES - Non-FTA (\$/kWh)								
Summer								
Peak	968,999,344	\$0.14032	\$135,970,907		968,999,344	\$0.12945	\$125,436,778	
Part-Peak	1,043,401,250	\$0.10163	\$106,041,859		1,043,401,250	\$0.08863	\$92,479,174	
Off-Peak	2,542,920,149	\$0.07173	\$182,406,074		2,542,920,149	\$0.07200	\$183,079,701	
Winter								
Part-Peak	1,803,608,970	\$0.09308	\$167,881,633		1,803,608,970	\$0.07899	\$142,458,945	
Off-Peak	2,283,346,496	\$0.07526	\$171,846,823		2,283,346,496	\$0.06957	\$158,862,723	
Revenue from Energy Charges			\$764,147,296		Revenue from Energy Charges			
Revenue from Energy as % of Total			67.61%		Revenue from Energy as % of Total			
					68.28%			
AVERAGE RATE LIMITER - Summer (\$/kWh)		\$0.20969			AVERAGE RATE LIMITER - Summer (\$/kWh)		\$0.20651	
CUSTOMER CHARGE (\$/meter/mo.)								
				(\$/meter/day)			(\$/meter/day)	
E-19	15,906	\$275	\$4,374,237	\$9.03	15,906	\$413	\$6,561,355	\$13.55
Rate V	96,857	\$99	\$9,574,336	\$3.25	96,857	\$120	\$11,622,866	\$3.94
Revenue from Customer Charges			\$13,948,573		Revenue from Customer Charges			
Revenue from Customer Chrg as % of Total			1.23%		Revenue from Customer Chrg as % of Total			
					1.77%			
POWER FACTOR ADJUSTMENT (\$/kWh)		\$0.00005			POWER FACTOR ADJUSTMENT (\$/kWh)		\$0.00005	
per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%			\$1,130,238,930	Total Rev	\$1,028,618,123			Total Rev Change
					-8.99%			
OPTIONAL METER DATA		\$0.98563	\$30.00		OPTIONAL METER DATA		\$0.98563	\$30.00
ACCESS CHARGE (\$/meter/day)		per day	per month		ACCESS CHARGE (\$/meter/day)		per day	per month

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

E-19 Primary
FIRM

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
DEMAND CHARGES (\$/kW)						
Summer						
Peak	940,267	\$10.61	\$9,976,238	940,267	\$10.31	\$9,692,463
Part-Peak	972,700	\$2.43	\$2,363,660	972,700	\$2.37	\$2,306,102
Maximum	1,037,472	\$4.78	\$4,959,116	1,037,472	\$6.24	\$6,478,994
Winter						
Part-Peak	904,482	\$0.76	\$687,406	904,482	\$0.78	\$708,475
Maximum	935,869	\$4.78	\$4,473,452	935,869	\$6.24	\$5,844,483
Revenue from Demand Charges			\$22,459,872			\$25,030,517
Revenue from Demand as % of Total			25.08%			28.54%
ENERGY CHARGES - Non-FTA (\$/kWh)						
Summer						
Peak	83,239,439	\$0.13126	\$10,926,088	83,239,439	\$0.12963	\$10,790,341
Part-Peak	92,778,773	\$0.09789	\$9,082,202	92,778,773	\$0.08727	\$8,097,252
Off-Peak	235,041,650	\$0.06977	\$16,399,079	235,041,650	\$0.06906	\$16,230,934
Winter						
Part-Peak	160,462,031	\$0.08833	\$14,173,763	160,462,031	\$0.07508	\$12,047,716
Off-Peak	211,396,538	\$0.07304	\$15,440,604	211,396,538	\$0.06579	\$13,908,175
Revenue from Energy Charges			\$66,021,736			\$61,074,418
Revenue from Energy as % of Total			73.71%			69.65%
AVERAGE RATE LIMITER - Summer (\$/kWh)		\$0.20969			\$0.20651	
CUSTOMER CHARGE (\$/meter/mo.)						
E-19	2,347	\$400	\$938,667	2,347	\$600	\$1,408,000
Rate V	1,495	\$99	\$147,810	1,495	\$120	\$179,436
Revenue from Customer Charges			\$1,086,477			\$1,587,436
Revenue from Customer Chrg as % of Total			1.21%			1.81%
POWER FACTOR ADJUSTMENT (\$/kWh)						
per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%		\$0.00005	\$89,568,085		\$0.00005	\$87,692,371
			Total Rev			Total Rev Change
						-2.09%
OPTIONAL METER DATA						
ACCESS CHARGE (\$/meter/day)		\$0.98563 per day	\$30.00 per month		\$0.98563 per day	\$30.00 per month

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

E-19 Transmission
Firm

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue		Billing Determinants	Rates	Revenue	
DEMAND CHARGES (\$/kW)								
Summer								
Peak	42,881	\$10.73	\$460,112		42,881	\$7.84	\$336,091	
Part-Peak	45,820	\$2.48	\$113,635		45,820	\$1.77	\$80,930	
Maximum	49,898	\$3.28	\$163,665		49,898	\$4.30	\$214,756	
Winter								
Part-Peak	43,410	\$0.00	\$0		43,410	\$0.00	\$0	
Maximum	44,543	\$3.28	\$146,099		44,543	\$4.30	\$191,707	
Revenue from Demand Charges			\$883,511		Revenue from Demand Charges			
Revenue from Demand as % of Total			25.21%		Revenue from Demand as % of Total			
ENERGY CHARGES - Non-FTA (\$/kWh)								
Summer								
Peak	3,049,760	\$0.10044	\$306,318		3,049,760	\$0.09552	\$291,299	
Part-Peak	3,671,900	\$0.09107	\$334,400		3,671,900	\$0.07664	\$281,405	
Off-Peak	9,254,257	\$0.06937	\$641,968		9,254,257	\$0.06537	\$604,948	
Winter								
Part-Peak	6,295,939	\$0.08713	\$548,565		6,295,939	\$0.06980	\$439,442	
Off-Peak	9,329,031	\$0.07255	\$676,821		9,329,031	\$0.06201	\$578,467	
Revenue from Energy Charges			\$2,508,072		Revenue from Energy Charges			
Revenue from Energy as % of Total			71.56%		Revenue from Energy as % of Total			
AVERAGE RATE LIMITER - Summer (\$/kWh)		N/A			AVERAGE RATE LIMITER - Summer (\$/kWh)		N/A	
CUSTOMER CHARGE (\$/meter/mo.)								
				(\$/meter/day)				(\$/meter/day)
E-19	100	\$1,030	\$102,974	\$33.83	100	\$1,200	\$120,000	\$39.43
Rate V	104	\$99	\$10,280	\$3.25	104	\$120	\$12,480	\$3.94
Revenue from Customer Charges			\$113,254		Revenue from Customer Charges			
Revenue from Customer Chrg as % of Total			3.23%		Revenue from Customer Chrg as % of Total			
POWER FACTOR ADJUSTMENT (\$/kWh)		\$0.00005			POWER FACTOR ADJUSTMENT (\$/kWh)		\$0.00005	
per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%			\$3,504,838	Total Rev		\$3,151,525	Total Rev	Change
								-10.08%
OPTIONAL METER DATA		\$0.98563			OPTIONAL METER DATA		\$0.98563	
ACCESS CHARGE (\$/meter/day)		per day		\$30.00	ACCESS CHARGE (\$/meter/day)		per day	
				per month			per month	

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

E-20 Transmission
Firm

	ESTIMATED MARCH 1, 2007 RATES (FEBRUARY 9 SETTLEMENT)			ILLUSTRATIVE RATES FOR MLLP RATE DESIGN SETTLEMENT		
	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
DEMAND CHARGES (\$/kW)						
Summer						
Peak	4,060,177	\$9.72	\$39,464,923	4,060,177	\$9.44	\$38,312,813
Part-Peak	4,167,563	\$2.11	\$8,793,559	4,167,563	\$2.11	\$8,814,324
Maximum	4,529,267	\$3.18	\$14,403,069	4,529,267	\$3.18	\$14,398,282
Winter						
Part-Peak	3,820,257	\$0.00	\$0	3,820,257	\$0.00	\$0
Maximum	3,947,263	\$3.18	\$12,552,298	3,947,263	\$3.18	\$12,548,126
Revenue from Demand Charges			\$75,213,849			\$74,073,545
Revenue from Demand as % of Total			23.32%			22.98%
ENERGY CHARGES (\$/kWh)						
Summer						
Peak	384,826,344	\$0.08111	\$31,213,265	384,826,344	\$0.08819	\$33,937,687
Part-Peak	442,669,667	\$0.07356	\$32,562,781	442,669,667	\$0.07076	\$31,323,163
Off-Peak	1,233,390,515	\$0.05605	\$69,131,538	1,233,390,515	\$0.06036	\$74,442,604
Winter						
Part-Peak	728,780,455	\$0.07039	\$51,298,856	728,780,455	\$0.06444	\$46,965,860
Off-Peak	1,053,393,784	\$0.05863	\$61,760,478	1,053,393,784	\$0.05725	\$60,308,341
Revenue from Energy Charges			\$245,966,918			\$246,977,655
Revenue from Energy as % of Total			76.26%			76.61%
AVERAGE RATE LIMITER - Summer (\$/kWh)		N/A			N/A	
CUSTOMER CHARGE (\$/meter/day)	1,334	\$1,030	\$1,373,275	1,334	\$1,005	\$1,340,442
			(\$/meter/day) \$33.83			(\$/meter/day) \$33.02
Revenue from Customer Charges			\$1,373,275			\$1,340,442
Revenue from Customer Chrg as % of Total			0.43%			0.42%
POWER FACTOR ADJUSTMENT (\$/kWh)		\$0.00005			\$0.00005	
per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%			\$322,554,042			\$322,391,642
			Total Rev			Total Rev Change
						-0.05%
OPTIONAL METER DATA		\$0.98563	\$30.00		\$0.98563	\$30.00
ACCESS CHARGE (\$/meter/day)		per day	per month		per day	per month

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

**SCHEDULE S
TRANSMISSION**

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
RESERVATION CHARGES (\$/kW)						
Summer						
Contract Capacity (rate applies to 85%)	4,448,725	\$0.72	\$2,706,141	4,448,725	\$0.74	\$2,803,047
Winter						
Contract Capacity (rate applies to 85%)	4,448,725	\$0.72	\$2,706,141	4,448,725	\$0.74	\$2,803,047
Revenue from Reservation Charges			\$5,412,282			\$5,606,095
Revenue from Reservation as % of Total			21.57%			21.80%
ENERGY CHARGES (\$/kWh)						
Summer						
Peak	8,984,894	\$0.09534	\$856,590	8,984,894	\$0.09949	\$893,917
Part-Peak	12,264,304	\$0.08771	\$1,075,750	12,264,304	\$0.08547	\$1,048,287
Off-Peak	60,917,575	\$0.07006	\$4,268,155	60,917,575	\$0.07711	\$4,697,266
Winter						
Part-Peak	60,091,833	\$0.08453	\$5,079,480	60,091,833	\$0.08040	\$4,831,158
Off-Peak	94,008,532	\$0.07267	\$6,831,485	94,008,532	\$0.07461	\$7,014,161
Revenue from Energy Charges			\$18,111,460			\$18,484,788
Revenue from Energy as % of Total			72.20%			71.90%
CUSTOMER CHARGE (\$/meter/mo.)						
Small-Single Phase (A-6)	0	\$8.10	\$0	0	\$12.00	\$0
Small-Polyphase (A-6)	0	\$12.00	\$0	0	\$18.00	\$0
Medium (>50 kW & <500 kW)	19	\$93.46	\$1,794	19	\$120.00	\$2,304
Medium (>500 kW & <1000 kW)	408	\$1,030.00	\$420,240	408	\$1,200.00	\$489,600
Large (>1000 kW)	1,104	\$1,030.00	\$1,137,120	1,104	\$1,017.29	\$1,123,083
Reduced - Medium	77	\$42.98	\$3,309	77	\$57.34	\$4,415
Revenue from Customer Charges			\$1,562,464			\$1,619,402
Revenue from Customer Chrg as % of Total			6.23%			6.30%
			\$25,086,206			\$25,710,285
						Total Rev Change 2.49%

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

SCHEDULE S
PRIMARY

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
RESERVATION CHARGES (\$/kW)						
Summer						
Contract Capacity (rate applies to 85%)	185,668	\$1.57	\$248,372	185,668	\$2.32	\$365,504
Winter						
Contract Capacity (rate applies to 85%)	185,668	\$1.57	\$248,372	185,668	\$2.32	\$365,504
Revenue from Reservation Charges			\$496,744			\$731,009
Revenue from Reservation as % of Total			28.26%			38.14%
ENERGY CHARGES (\$/kWh)						
Summer						
Peak	567,829	\$0.23462	\$133,225	567,829	\$0.26379	\$149,785
Part-Peak	649,312	\$0.17936	\$116,458	649,312	\$0.16039	\$104,145
Off-Peak	2,565,947	\$0.13059	\$335,096	2,565,947	\$0.12086	\$310,112
Winter						
Part-Peak	1,596,410	\$0.16613	\$265,219	1,596,410	\$0.14062	\$224,494
Off-Peak	2,418,632	\$0.13578	\$328,408	2,418,632	\$0.11850	\$286,602
Revenue from Energy Charges			\$1,178,406			\$1,075,139
Revenue from Energy as % of Total			67.05%			56.10%
CUSTOMER CHARGE (\$/meter/mo.)						
Small-Single Phase (A-6)	0	\$8.10	\$0	0	\$12.00	\$0
Small-Polyphase (A-6)	0	\$12.00	\$0	0	\$18.00	\$0
Medium (>50 kW & <500 kW)	48	\$93.46	\$4,486	48	\$120.00	\$5,760
Medium (>500 kW & <1000 kW)	72	\$400.00	\$28,800	72	\$600.00	\$43,200
Large (>1000 kW)	60	\$800.00	\$48,000	60	\$1,000.00	\$60,000
Reduced - Medium	24	\$42.98	\$1,032	24	\$57.34	\$1,376
Revenue from Customer Charges			\$82,318			\$110,336
Revenue from Customer Chrg as % of Total			4.68%			5.76%
			\$1,757,467			\$1,916,484
						Total Rev Change 9.05%

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

**SCHEDULE S
SECONDARY**

**ESTIMATED MARCH 1, 2007 RATES
(FEBRUARY 9 SETTLEMENT)**

**ILLUSTRATIVE RATES FOR MLLP RATE
DESIGN SETTLEMENT**

	Billing Determinants	Rates	Revenue	Billing Determinants	Rates	Revenue
RESERVATION CHARGES (\$/kW)						
Summer						
Contract Capacity (rate applies to 85%)	235,590	\$1.61	\$322,043	235,590	\$2.34	\$468,625
Winter						
Contract Capacity (rate applies to 85%)	235,590	\$1.61	\$322,043	235,590	\$2.34	\$468,625
Revenue from Reservation Charges			\$644,085			\$937,250
Revenue from Reservation as % of Total			26.63%			37.29%
ENERGY CHARGES (\$/kWh)						
Summer						
Peak	795,827	\$0.24461	\$194,669	795,827	\$0.26500	\$210,890
Part-Peak	855,696	\$0.18436	\$157,755	855,696	\$0.15988	\$136,808
Off-Peak	2,854,662	\$0.13273	\$378,885	2,854,662	\$0.11977	\$341,897
Winter						
Part-Peak	2,558,321	\$0.17261	\$441,600	2,558,321	\$0.14134	\$361,604
Off-Peak	4,190,929	\$0.13820	\$579,168	4,190,929	\$0.11742	\$492,113
Revenue from Energy Charges			\$1,752,079			\$1,543,312
Revenue from Energy as % of Total			72.45%			61.40%
CUSTOMER CHARGE (\$/meter/mo.)						
Small-Single Phase (A-6)	668	\$8.10	\$5,411	668	\$12.00	\$8,016
Small-Polyphase (A-6)	928	\$12.00	\$11,136	928	\$18.00	\$16,704
Medium (>50 kW & <500 kW)	18	\$93.46	\$1,682	18	\$120.00	\$2,160
Medium (>500 kW & <1000 kW)	12	\$275.00	\$3,300	12	\$412.50	\$4,950
Large (>1000 kW)	0	\$600.00	\$0	0	\$750.00	\$0
Reduced - Medium	18	\$42.98	\$774	18	\$57.34	\$1,032
Revenue from Customer Charges			\$22,303			\$32,862
Revenue from Customer Chrg as % of Total			0.92%			1.31%
			\$2,418,466			\$2,513,424
						Total Rev Change 3.93%

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

ILLUSTRATIVE FUNCTIONAL RATES FOR MLLP SETTLEMENT
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**A-10 Secondary
BUNDLED**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Maximum	\$3.55	\$2.62	\$0.00	\$2.97	\$9.14
Winter					
Maximum	\$2.36	\$0.00	\$0.00	\$2.97	\$5.33
ENERGY CHARGES - Non-FTA (\$/kWh)					
Summer					
Total	\$0.01751	\$0.08391	\$0.01003	\$0.00776	\$0.11921
Winter					
Total	\$0.01168	\$0.06086	\$0.01003	\$0.00776	\$0.09033

**A-10 Primary
BUNDLED**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Maximum	\$2.91	\$2.70	\$0.00	\$2.97	\$8.58
Winter					
Maximum	\$1.93	\$0.00	\$0.00	\$2.97	\$4.90
ENERGY CHARGES - Non-FTA (\$/kWh)					
Summer					
Total	\$0.01409	\$0.08161	\$0.00978	\$0.00776	\$0.11324
Winter					
Total	\$0.00939	\$0.05881	\$0.00978	\$0.00776	\$0.08574

**A-10 Transmission
BUNDLED**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Maximum	\$0.32	\$3.05	\$0.00	\$2.97	\$6.33
Winter					
Maximum	\$0.20	\$0.00	\$0.00	\$2.97	\$3.17
ENERGY CHARGES - Non-FTA (\$/kWh)					
Summer					
Total	\$0.00135	\$0.07969	\$0.00943	\$0.00776	\$0.09824
Winter					
Total	\$0.00090	\$0.05748	\$0.00943	\$0.00776	\$0.07558

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

ILLUSTRATIVE FUNCTIONAL RATES FOR MLLP SETTLEMENT

**A-10 Secondary
TOU**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Maximum	\$3.55	\$2.62	\$0.00	\$2.97	\$9.14
Winter					
Maximum	\$2.36	\$0.00	\$0.00	\$2.97	\$5.33
ENERGY CHARGES (\$/kWh)					
Summer					
Peak	\$0.01751	\$0.10339	\$0.01003	\$0.00776	\$0.13869
Part-Peak	\$0.01751	\$0.08420	\$0.01003	\$0.00776	\$0.11951
Off-Peak	\$0.01751	\$0.07279	\$0.01003	\$0.00776	\$0.10809
Winter					
Part-Peak	\$0.01168	\$0.06551	\$0.01003	\$0.00776	\$0.09498
Off-Peak	\$0.01168	\$0.05637	\$0.01003	\$0.00776	\$0.08583

**A-10 Primary
TOU**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Maximum	\$2.91	\$2.70	\$0.00	\$2.97	\$8.58
Winter					
Maximum	\$1.93	\$0.00	\$0.00	\$2.97	\$4.90
ENERGY CHARGES (\$/kWh)					
Summer					
Peak	\$0.01409	\$0.09914	\$0.00978	\$0.00776	\$0.13077
Part-Peak	\$0.01409	\$0.08208	\$0.00978	\$0.00776	\$0.11371
Off-Peak	\$0.01409	\$0.07149	\$0.00978	\$0.00776	\$0.10312
Winter					
Part-Peak	\$0.00939	\$0.06247	\$0.00978	\$0.00776	\$0.08940
Off-Peak	\$0.00939	\$0.05528	\$0.00978	\$0.00776	\$0.08221

**A-10 Transmission
TOU**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Maximum	\$0.32	\$3.05	\$0.00	\$2.97	\$6.33
Winter					
Maximum	\$0.20	\$0.00	\$0.00	\$2.97	\$3.17
ENERGY CHARGES (\$/kWh)					
Summer					
Peak	\$0.00135	\$0.09645	\$0.00943	\$0.00776	\$0.11499
Part-Peak	\$0.00135	\$0.07996	\$0.00943	\$0.00776	\$0.09851
Off-Peak	\$0.00135	\$0.07012	\$0.00943	\$0.00776	\$0.08867
Winter					
Part-Peak	\$0.00090	\$0.06094	\$0.00943	\$0.00776	\$0.07903
Off-Peak	\$0.00090	\$0.05414	\$0.00943	\$0.00776	\$0.07223

Pacific Gas and Electric Company
2007 GRC Rate Design Changes

ILLUSTRATIVE FUNCTIONAL RATES FOR MLLP SETTLEMENT

**E-19 Secondary
FIRM**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Peak	\$3.61	\$7.78	N/A	\$0.00	\$11.40
Part-Peak	\$0.97	\$1.66	N/A	\$0.00	\$2.63
Maximum	\$4.31	\$0.00	N/A	\$2.97	\$7.28
Winter					
Part-Peak	\$1.04	\$0.00	N/A	\$0.00	\$1.04
Maximum	\$4.31	\$0.00	N/A	\$2.97	\$7.28
ENERGY CHARGES - Non-FTA (\$/kWh)					
Summer					
Peak	\$0.01196	\$0.10029	\$0.00947	\$0.00773	\$0.12945
Part-Peak	\$0.00479	\$0.06665	\$0.00947	\$0.00773	\$0.08863
Off-Peak	\$0.00239	\$0.05240	\$0.00947	\$0.00773	\$0.07200
Winter					
Part-Peak	\$0.00407	\$0.05771	\$0.00947	\$0.00773	\$0.07899
Off-Peak	\$0.00272	\$0.04966	\$0.00947	\$0.00773	\$0.06957

**E-19 Primary
FIRM**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Peak	\$2.78	\$7.53	N/A	\$0.00	\$10.31
Part-Peak	\$0.75	\$1.62	N/A	\$0.00	\$2.37
Maximum	\$3.28	\$0.00	N/A	\$2.97	\$6.24
Winter					
Part-Peak	\$0.78	\$0.00	N/A	\$0.00	\$0.78
Maximum	\$3.28	\$0.00	N/A	\$2.97	\$6.24
ENERGY CHARGES - Non-FTA (\$/kWh)					
Summer					
Peak	\$0.00961	\$0.10337	\$0.00892	\$0.00773	\$0.12963
Part-Peak	\$0.00384	\$0.06678	\$0.00892	\$0.00773	\$0.08727
Off-Peak	\$0.00192	\$0.05049	\$0.00892	\$0.00773	\$0.06906
Winter					
Part-Peak	\$0.00324	\$0.05520	\$0.00892	\$0.00773	\$0.07508
Off-Peak	\$0.00216	\$0.04699	\$0.00892	\$0.00773	\$0.06579

**E-19 Transmission
Firm**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Peak	\$0.00	\$7.84	N/A	\$0.00	\$7.84
Part-Peak	\$0.00	\$1.77	N/A	\$0.00	\$1.77
Maximum	\$1.34	\$0.00	N/A	\$2.97	\$4.30
Winter					
Part-Peak	\$0.00	\$0.00	N/A	\$0.00	\$0.00
Maximum	\$1.34	\$0.00	N/A	\$2.97	\$4.30
ENERGY CHARGES - Non-FTA (\$/kWh)					
Summer					
Peak	\$0.00000	\$0.07882	\$0.00896	\$0.00773	\$0.09552
Part-Peak	\$0.00000	\$0.05995	\$0.00896	\$0.00773	\$0.07664
Off-Peak	\$0.00000	\$0.04868	\$0.00896	\$0.00773	\$0.06537
Winter					
Part-Peak	\$0.00000	\$0.05311	\$0.00896	\$0.00773	\$0.06980
Off-Peak	\$0.00000	\$0.04532	\$0.00896	\$0.00773	\$0.06201

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ILLUSTRATIVE FUNCTIONAL RATES FOR MLLP SETTLEMENT

**E-20 Secondary
Firm**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Peak	\$3.65	\$7.43	N/A	\$0.00	\$11.08
Part-Peak	\$0.95	\$1.52	N/A	\$0.00	\$2.47
Maximum	\$4.27	\$0.00	N/A	\$3.18	\$7.45
Winter					
Part-Peak	\$1.04	\$0.00	N/A	\$0.00	\$1.04
Maximum	\$4.27	\$0.00	N/A	\$3.18	\$7.45
ENERGY CHARGES (\$/kWh)					
Summer					
Peak	\$0.01148	\$0.09503	\$0.00920	\$0.00774	\$0.12346
Part-Peak	\$0.00459	\$0.06362	\$0.00920	\$0.00774	\$0.08515
Off-Peak	\$0.00230	\$0.05018	\$0.00920	\$0.00774	\$0.06942
Winter					
Part-Peak	\$0.00394	\$0.05526	\$0.00920	\$0.00774	\$0.07615
Off-Peak	\$0.00263	\$0.04755	\$0.00920	\$0.00774	\$0.06712

**E-20 Primary
Firm**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Peak	\$2.39	\$8.05	N/A	\$0.00	\$10.44
Part-Peak	\$0.65	\$1.76	N/A	\$0.00	\$2.41
Maximum	\$2.93	\$0.00	N/A	\$3.18	\$6.11
Winter					
Part-Peak	\$0.67	\$0.00	N/A	\$0.00	\$0.67
Maximum	\$2.93	\$0.00	N/A	\$3.18	\$6.11
ENERGY CHARGES (\$/kWh)					
Summer					
Peak	\$0.00768	\$0.10217	\$0.00856	\$0.00772	\$0.12613
Part-Peak	\$0.00307	\$0.06592	\$0.00856	\$0.00772	\$0.08527
Off-Peak	\$0.00154	\$0.04982	\$0.00856	\$0.00772	\$0.06763
Winter					
Part-Peak	\$0.00255	\$0.05446	\$0.00856	\$0.00772	\$0.07328
Off-Peak	\$0.00170	\$0.04637	\$0.00856	\$0.00772	\$0.06435

**E-20 Transmission
Firm**

	Distr	Gen	PPP	Other	Total
DEMAND CHARGES (\$/kW)					
Summer					
Peak	\$0.00	\$9.44	N/A	\$0.00	\$9.44
Part-Peak	\$0.00	\$2.11	N/A	\$0.00	\$2.11
Maximum	\$0.00	\$0.00	N/A	\$3.18	\$3.18
Winter					
Part-Peak	\$0.00	\$0.00	N/A	\$0.00	\$0.00
Maximum	\$0.00	\$0.00	N/A	\$3.18	\$3.18
ENERGY CHARGES (\$/kWh)					
Summer					
Peak	\$0.00000	\$0.07298	\$0.00750	\$0.00771	\$0.08819
Part-Peak	\$0.00000	\$0.05555	\$0.00750	\$0.00771	\$0.07076
Off-Peak	\$0.00000	\$0.04514	\$0.00750	\$0.00771	\$0.06036
Winter					
Part-Peak	\$0.00000	\$0.04923	\$0.00750	\$0.00771	\$0.06444
Off-Peak	\$0.00000	\$0.04204	\$0.00750	\$0.00771	\$0.05725

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ILLUSTRATIVE FUNCTIONAL RATES FOR MLLP SETTLEMENT

**SCHEDULE S
TRANSMISSION**

	Distr	Gen	PPP	Other	Total
RESERVATION CHARGES (\$/kW)					
Summer					
Contract Capacity (rate applies to 85%)	\$0.20	\$0.17	\$0.00	\$0.36	\$0.74
Winter					
Contract Capacity (rate applies to 85%)	\$0.20	\$0.17	\$0.00	\$0.36	\$0.74
ENERGY CHARGES (\$/kWh)					
Summer					
Peak	\$0.00000	\$0.07092	\$0.00908	\$0.01949	\$0.09949
Part-Peak	\$0.00000	\$0.05690	\$0.00908	\$0.01949	\$0.08547
Off-Peak	\$0.00000	\$0.04854	\$0.00908	\$0.01949	\$0.07711
Winter					
Part-Peak	\$0.00000	\$0.05182	\$0.00908	\$0.01949	\$0.08040
Off-Peak	\$0.00000	\$0.04604	\$0.00908	\$0.01949	\$0.07461

**SCHEDULE S
PRIMARY**

	Distr	Gen	PPP	Other	Total
RESERVATION CHARGES (\$/kW)					
Summer					
Contract Capacity (rate applies to 85%)	\$1.78	\$0.17	\$0.00	\$0.36	\$2.32
Winter					
Contract Capacity (rate applies to 85%)	\$1.78	\$0.17	\$0.00	\$0.36	\$2.32
ENERGY CHARGES (\$/kWh)					
Summer					
Peak	\$0.14291	\$0.08894	\$0.01244	\$0.01949	\$0.26379
Part-Peak	\$0.05716	\$0.07129	\$0.01244	\$0.01949	\$0.16039
Off-Peak	\$0.02858	\$0.06034	\$0.01244	\$0.01949	\$0.12086
Winter					
Part-Peak	\$0.04407	\$0.06461	\$0.01244	\$0.01949	\$0.14062
Off-Peak	\$0.02938	\$0.05718	\$0.01244	\$0.01949	\$0.11850

**SCHEDULE S
SECONDARY**

	Distr	Gen	PPP	Other	Total
RESERVATION CHARGES (\$/kW)					
Summer					
Contract Capacity (rate applies to 85%)	\$1.78	\$0.20	\$0.00	\$0.36	\$2.34
Winter					
Contract Capacity (rate applies to 85%)	\$1.78	\$0.20	\$0.00	\$0.36	\$2.34
ENERGY CHARGES (\$/kWh)					
Summer					
Peak	\$0.14291	\$0.09096	\$0.01163	\$0.01949	\$0.26500
Part-Peak	\$0.05716	\$0.07159	\$0.01163	\$0.01949	\$0.15988
Off-Peak	\$0.02858	\$0.06006	\$0.01163	\$0.01949	\$0.11977
Winter					
Part-Peak	\$0.04407	\$0.06614	\$0.01163	\$0.01949	\$0.14134
Off-Peak	\$0.02938	\$0.05691	\$0.01163	\$0.01949	\$0.11742

EXHIBIT B

PRO FORMA TARIFF LANGUAGE FOR

STANDBY SERVICE SCHEDULE S

The Settling Parties agree to modify Special Conditions 1 and 2 of the Schedule S tariff to read as provided herein. These modifications will replace the current ratchet provisions for standby customer Reservation Capacity with an annual review procedure (Special Condition 1), and will replace the current method of administering and billing the Reactive Demand Charge with a new system that includes provisions for exemptions from this charge for customers who are required or agree to comply with voltage regulation orders issued by PG&E (as described in the revised Special Condition 2).

The Settling Parties also agree that it is reasonable to increase the Reactive Demand Charge rate under Schedule S from its current level of \$0.15 to \$0.35 per kVAR, except in those instances and for those customers where the Reactive Demand Charge is waived subject to the provisions of the revised Special Condition 2. The Settling Parties also agree that the revised Reactive Demand Charge provisions will be the only reactive power-related charges that are billed under Schedule S. Accordingly, the Settling Parties agree that Special Condition 8 (“Power Factor Adjustment”) should be removed from the Schedule S tariff.

The Settling Parties agree further that both real and reactive power demands should continue to be measured on a 15-minute basis, and that this standard should be added to the Applicability section of the Schedule S tariff, using the same definitions that are already part of the Schedule A-10, E-19 and E-20 tariffs:

Definition of Maximum Demand: The real (kW) and reactive (kVAR) demands billed under this tariff will be averaged over 15-minute intervals. “Maximum demand” (real and reactive) will be the highest of all of the 15-minute averages for the billing month. If the customer’s use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals.

The Settling Parties agree to modify Special Conditions 1 and 2 of the standby tariff to read as follows:

1. RESERVATION CAPACITY:

The Reservation Capacity to be used for billing under the above rates shall be as set forth in the customer's contract for service as amended consistent with this Special Condition 1. For new or revised contracts, the Reservation Capacity shall be set as initially determined by the customer, except that during the first 12 month period following the date of initial specification, PG&E may review the specified Reservation Capacity on a monthly basis and make adjustments as warranted (consistent with the criteria specified below). Thereafter, PG&E may perform an annual review of the most recent 12 months of actual customer operation and make prospective adjustments to the Reservation Capacity as warranted and consistent with customer's historic operations. Any such adjusted Reservation Capacity shall be effective for a minimum of 12 months unless a documented material change of operation is provided to PG&E by customer. Customer may provide PG&E with documentation of such material changes in operations as might call for an adjusted Reservation Capacity at any time. Upon receipt and review of such documentation, PG&E shall revise the Reservation Capacity effective for the billing period immediately following receipt of the documentation.

For purposes of the subsequent annual contract reviews and any resulting adjustment to the Reservation Capacity, the following criteria shall apply:

- a. For those customers who operate sufficient non-utility generating capacity so as to ordinarily satisfy all of the electric energy requirements at their site and so do not ordinarily require any service through facilities owned by PG&E, the Reservation Capacity shall not be any greater than the customer's hourly peak demand established during the most recent 12 months of actual customer operation;
- b. For customers with electric loads that exceed the capability of their non-utility generation so as to require the regular provision of supplemental power service through facilities owned by PG&E, the Reservation Capacity determination shall consider the number and size of the customer's non-utility generating unit(s), the outage diversity of the non-utility generating units serving the customer's load and any reduction of customer load commensurate with non-utility generator capacity outages; and

For customers taking Extended Outage Service under Special Condition 9 to this tariff, the Reservation Capacity recorded during the period of Extended Outage Service shall be considered only for purposes of billing customer for Extended Outage Service, and shall not be considered in PG&E's determination of customer Reservation Capacity for purposes of other standby service taken under this tariff outside of Extended Outage Service periods. See Special Condition 7 of this tariff for the definition of Reservation Capacity for Supplemental Standby Service customers.

2. REACTIVE DEMAND CHARGE:

When the customer's non-utility generation equipment is operated in parallel with PG&E's system, the customer will design and attempt to operate its facilities in such a way that the reactive current requirements of that portion of the customer's load which is ordinarily supplied from the customer's generation is not supplied at any time from PG&E's system. If the customer does place a reactive demand on PG&E's system in any month, the customer's monthly bill will be adjusted as follows:

- a. A monthly Reactive Demand Charge power factor is computed from the ratio of lagging maximum reactive kilovolt-amperes consumed in the month to the Reservation Capacity kilowatts. This power factor is rounded to the nearest whole percent.
- b. If the calculated monthly Reactive Demand Charge power factor is below 95 percent, the total monthly bill will be increased by the product of the maximum reactive kilovolt-amperes consumed in the month and the Reactive Demand Charge rate.

Those customers operating synchronous generators who are otherwise obligated to comply with PG&E switching center voltage orders are exempt from the Reactive Demand Charge, provided that customer is in compliance with all valid PG&E switching center voltage orders. Those customers operating synchronous generators who are not otherwise obligated to comply with PG&E switching center voltage orders may elect to comply with voltage orders on a voluntary basis and thereby receive the same exemption from the Reactive Demand Charge as is received by customers subject to mandatory voltage order obligations.

A customer who is operating under PG&E switching center voltage orders will become exempt from the Reactive Demand Charge after providing PG&E with the following written information:

- a. Notification requesting an exemption including the name, address, and telephone number of the party requesting the exemption;
- b. The location, telephone number, electronic mail address and Fax number of the entity to which PG&E switching center orders are to be transmitted; and
- c. The generator equipment limits for operating voltages and plus and minus VARs.

Customers operating synchronous generators subject to exemption from paying the Reactive Demand Charge must comply with valid PG&E switching center voltage orders, as defined below for the purposes of this Special Condition 2. Upon request, the customer shall provide PG&E with written documentation sufficient to confirm customer's compliance with valid PG&E switching center voltage orders. Failure of the customer to comply with a valid PG&E switching center voltage order shall result in the following actions by PG&E:

- a. On the initial noncompliance occurrence or an occurrence of noncompliance following the imposition of a penalty, PG&E will provide to the customer in writing, through U.S.

or electronic mail, the date and nature of the noncompliance and notice that another failure to comply within the next 12 months will result in assessment of a penalty.

- b. On any second or further event of noncompliance within 12 months of the prior noncompliance occurrence, a penalty will be billed to the account, equal to the lesser of the number of months since the last noncompliance penalty and the number 12, multiplied by the highest created Reactive Demand in the most recent noncompliance period, multiplied by the current Reactive Demand Charge rate.
- c. Customer eligibility for the exemption shall not be interrupted after a subsequent noncompliance occurrence (after a prior warning has been issued). However, a penalty for noncompliance as described here will be billed to the account.

A valid PG&E switching center voltage order shall specify the requested operating voltage, as measured at the customer's generator terminals (or some other mutually agreeable metering location), and shall request operation of the customer's generator within a power factor range that is no stricter than: (1) the customer's power factor range obligation as specified in a contractual agreement (if any); (2) the minimum power factor range specified by the applicable CAISO tariff; or (3) the customer specified generator equipment limits.

Notwithstanding any other provision of this Special Condition 2, a valid PG&E switching center voltage order request shall ordinarily allow operation of the customer's generator within a power factor range that does not require the generator to reduce its MW output in order to comply with such request, with exceptions only to occur on an emergency basis, such as the unexpected loss of a major transmission line or large generation facility, or under extreme weather and/or system peak load conditions. No such exceptional voltage order request need be treated as valid if compliance with such a request would conflict with any protections that might be afforded to the customer's load in those instances where a valid Essential Use Customer designation applies to the load at the site.