ATTACHMENT A
SETTLEMENT AGREEMENT

SETTLEMENT OF ISSUES RELATED TO MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN IN PHASE 2 OF SOUTHERN CALIFORNIA EDISON COMPANY'S 2006 GENERAL RATE CASE (PHASE 2 SETTLEMENT AGREEMENT)

This Phase 2 Settlement Agreement (Agreement or Settlement Agreement) is entered into by and among the undersigned Parties hereto, with reference to the following:

1. Parties

The Parties to this Agreement are Southern California Edison Company (SCE); The Utility Reform Network (TURN); the Division of Ratepayer Advocates (DRA); California Farm Bureau Federation (CFBF); Agricultural Energy Consumers Association (AECA); Federal Executive Agencies (FEA); California Manufacturers and Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Indicated Commercial Parties (ICP); California City-County Street Light Association (CAL-SLA); the Western Manufactured Housing Community Association (WMA); the Vote Solar Initiative (Vote Solar); the Building Owners and Managers Associations of Greater Los Angeles, Orange County, San Francisco, and California (BOMA); and the Cogeneration Association of California and Energy Producers and Users Coalition (CAC/EPUC) (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

2. Recitals

a. SCE is an investor-owned public utility and is subject to the jurisdiction of the California Public Utilities Commission (Commission or CPUC) with respect to providing electric service to its CPUC-jurisdictional retail customers.

ATTACHMENT A
SETTLEMENT AGREEMENT

b. TURN is an independent, non-profit consumer advocacy organization that represents the interests of residential and small commercial utility customers.

c. DRA is a division of the Commission that represents the interests of public utility customers. Its goal is to obtain the lowest possible rate for service consistent with reliable and safe service levels. Pursuant to Public Utilities Code Section 309.5(a), the DRA is directed to primarily consider the interests of residential and small commercial customers in revenue allocation and rate design matters.

d. CFBF is a voluntary, private, non-profit corporation representing more than 89,000 members and over 80 percent of California's commercial agriculture.

e. AECA represents individual agricultural producers, processors, produce-cooling operations, agricultural water agencies and member agricultural associations, many of which are customers of SCE and Pacific Gas & Electric Company.

f. FEA represents the consumer interests of all Federal executive agencies that take utility service from Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas and Electric Company.

g. CMTA is a trade association with over 500 members operating in the manufacturing and high technology sectors of the California economy. Many of its members receive electrical service from SCE either as bundled or direct access customers.

h. CLECA is an organization of large, high voltage and high load factor industrial customers of SCE and Pacific Gas and Electric Company, many of whom are served under interruptible tariff options.

ATTACHMENT A
SETTLEMENT AGREEMENT

i. ICP is an ad hoc group composed of government, health care, and retail entities who receive service on commercial rate schedules. The members of ICP include the County of Los Angeles, the Los Angeles Unified School District, Catholic Healthcare West, and Lowe's Home Improvement Warehouses, Inc.

j. CAL-SLA represents cities and counties that take street and area lighting and traffic signal services from SCE and the other two major investor-owned utilities, Pacific Gas & Electric and San Diego Gas & Electric.

k. WMA is a not-for-profit trade association that represents the owners of both submetered and directly-served manufactured housing communities in California

l. BOMA consists of associations of commercial real estate professionals that own, manage, or otherwise service commercial office buildings in SCE's service territory and within California. BOMA members own or manage in excess of 600 million square feet of commercial office space that is occupied by small and medium sized businesses.

m. CAC represents the power generation, power marketing and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

ATTACHMENT A
SETTLEMENT AGREEMENT

n. EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP America Inc. (including Atlantic Richfield Company), Chevron U.S.A. Inc., Conoco Phillips Company, ExxonMobil Power & Gas Services, Inc., Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company – California

o. Vote Solar is a non-profit organization with members throughout California and the country who want a rapid transition to a clean and renewable energy future.

3. Background

a. In Phase 2 of SCE's General Rate Case, the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

b. On May 20, 2005, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design. SCE updated its initial showing on September 6, 2005.

c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated August 15, 2005, SCE provided notice to all parties of its intent to conduct a settlement conference related to potential issues and an initial settlement conference was held on November 14, 2005.

d. DRA served its initial testimony on December 16, 2005. Interveners served their initial testimony on January 20, 2006.

ATTACHMENT A
SETTLEMENT AGREEMENT

e. On January 18, 2006, SCE once again provided notice to all parties of a settlement conference to occur on January 26, 2006 related to potential settlement of issues in this proceeding. Continuing settlement discussions occurred among the interested parties after January 26, 2006.

f. The Parties have evaluated the impacts of the various proposals in Phase 2 of this proceeding, and have reached agreement as indicated in Section 6 of this Agreement.

4. Comparison Exhibit

As required by Rule 51.1(c), because this settlement pertains to a proceeding under the Rate Case Plan, SCE and DRA have provided a comparison exhibit indicating the relative impact of the Agreement compared to SCE's and DRA's respective litigation positions. Those comparisons are provided in Appendix A to this Agreement.

5. Definitions

When used in initial capitalization in this agreement, whether in singular or plural, the following terms shall have the following meanings:

a. "Agreement" shall have the meaning given to such term in the introductory paragraph hereof.

b. "Basic Charge" means the customer charge applied to customers in the Domestic Rate Group, as differentiated for single-family and multi-family residences.

c. "DWR" means the California Department of Water Resources.

ATTACHMENT A
SETTLEMENT AGREEMENT

d. “DWR Revenue Requirement” means the revenues collected by SCE on behalf of the DWR to recover the DWR’s costs of power procurement that have been allocated to SCE and the costs of repaying the bonds that were issued to repay the General Fund of California. It consists of both the DWR Power Charge revenue requirement and the DWR Bond Charge revenue requirement.

e. “FERC” means the Federal Energy Regulatory Commission.

f. “Loss of Load Probability” means the probability that available generation capacity will be inadequate to supply customer demand at any given moment.

g. “Marginal Cost” means the change in total cost due to a small change in the quantity produced or provided.

h. “NCO” means New Customer Only, and is a method used to derive marginal customer costs, taking into account the capital cost of adding new customers only and other O&M costs.

i. “Primary Voltage” means facilities at which electric power is taken or delivered, generally between 12 kV and 33 kV, but always between 2 kV and 50 kV.

j. “Rate Case Plan” means D. 89-01-040, as modified by D. 93-07-030 for processing by the Commission of SCE rate cases.

k. “Real Economic Carrying Charge” or RECC means a measure of the per dollar savings of deferring an investment one year, taking into account the stream of replacement investments.

ATTACHMENT A
SETTLEMENT AGREEMENT

l. “Secondary Voltage” means facilities at which electric power is taken or delivered, generally between 120 volts and 480 volts, but always less than 2 kV.

m. “Settling Parties” means SCE, DRA, TURN, CFBF, AECA, ICP, CMTA, CLECA, FEA, WMA, CAL-SLA, BOMA, Vote Solar and CAC/EPUC.

n. “Subtransmission Voltage” means facilities at which electric power is taken or delivered, generally greater than 50 kV and less than 220 kV.

o. “TOU” means time-of-use. These are the time periods established for provision of electric service in which demand or energy charges may vary in relation to the cost of service.

p. “Trust Transfer Amount”’ means the revenues collected via non-bypassable charges from customers in the residential and small commercial customer rate groups that were eligible for the 10 percent rate reduction implemented in accordance with Public Utilities Code Section 368. This revenue is used to pay principal and interest on the bonds that were used to finance the 10 percent rate reduction.

6. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Parties agree to the terms of this Agreement. Nothing in this Agreement shall be deemed to constitute an admission or an acceptance by any Party of any fact, principle, or position contained herein and this Agreement is subject to the limitations described in Section 12 with respect to the express limitation on precedent. The Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of the Agreement.

ATTACHMENT A
SETTLEMENT AGREEMENT

a. **Marginal Costs**

This Agreement does not use any of the Parties' marginal cost proposals as the basis for the agreed-upon Phase 2 Revenue Allocation Agreement which is provided in Appendix B. Except as otherwise expressly provided in this Agreement, for the sole purpose of establishing unit marginal costs that are used where applicable to set floors for energy, customer, or demand charges for certain customer classes, the Settling Parties agree that it is reasonable to use the following marginal costs:

i. **Generation Marginal Energy and Capacity Costs**

Generation marginal energy costs are based on a forecast gas price of $8.82 per million BTUs averaged over 36 months starting February 2006. The hourly marginal energy costs derived from this gas price forecast using SCE's methodology are averaged by TOU periods. Generation marginal capacity cost is based on the deferral value of a gas-fired combustion turbine (CT), with the installation cost annualized using SCE's Real Economic Carrying Charge (RECC) methodology, yielding a generation marginal capacity cost of $74.69 per kW per year which is allocated to TOU periods by the loss of load probability measure. This generation marginal capacity cost is also the basis for establishing the interruptible rate credit. Generation marginal costs by season and time-of-use periods are as follows:

ATTACHMENT A
SETTLEMENT AGREEMENT

Generation Marginal Cost (2006$)						
		Summer			Winter	
	On-Peak	Mid-Peak	Off-Peak		Mid-Peak	Off-Peak
Energy Cost (¢/kWh) Average 6.21 ¢/kWh	9.18	7.32	5.04		7.60	5.30
CT Proxy ($/kW-year): Annual $74.69/kW-year	52.36	15.31	0.67		6.05	0.30
Relative Loss of Load Probability	70.1%	20.5%	0.9%		8.1%	0.4%

Notes: Energy cost is an average over 36 months, with a corresponding natural gas price of $8.82 per MM Btu. The CT proxy is based on a forecast installed cost of $542/kW, adjusted to 2006$. These costs are forecast at the generator level.

ii. **Marginal Customer Cost**

Marginal customer costs shall be as follows:

Rate Group	$/customer-month
Domestic	8.39
GS-1	12.52
TC-1	9.20
GS-2	99.35
TOU-GS-3	269.10
TOU-8-Primary	202.22
TOU-8-Secondary	335.78
TOU-8-Subtransmission	1779.57
PA-1	57.08
PA-2	85.92
AG-TOU	137.64
TOU-PA-5	148.78
Street Lighting	6.79

ATTACHMENT A
SETTLEMENT AGREEMENT

iii. **Marginal Distribution Capacity Cost**

Marginal distribution costs are calculated by estimating the incremental cost of adding distribution capacity to meet demand, using ten years of historical data and a five-year forecast.

Distribution Marginal Cost (2006$)	**System** Design Demand ($/kW-year)
ISO Transmission (220 kV)	23.32
Non-ISO Subtransmission (66 kV)	23.92
Distribution (12 kV)	71.83

b. **Revenue Allocation**

The Settling Parties agree that the revenue allocation results listed in Appendix B of this Agreement ("Phase 2 Revenue Allocation Agreement") are reasonable and should be adopted by the Commission. The Phase 2 Revenue Allocation Agreement reflects all of SCE's adopted revenue requirements, including transmission, distribution, SCE generation, nuclear decommissioning, public purpose programs, trust transfer amount, and the DWR Power Charge and DWR Bond Charge revenue requirements as of the date of this Agreement, with forecast revenue requirement changes for Phase 1 of SCE's 2006 GRC in A.04-12-024 and SCE's FERC rate case in ER06-186.

ATTACHMENT A
SETTLEMENT AGREEMENT

i. **Revenue Requirement and Allocation Principles**

All of SCE's rate groups have received significant revenue requirement increases that either have occurred or are expected to occur and to be reflected in rates over the period from December 2005 through June 2006. These revenue changes have had disparate impacts on different rate groups when applied based on the functional System Average Percent Change (SAPC) methodology in accordance with the settlement agreement adopted in D.05-03-022 in Phase 2 of SCE's 2003 GRC. In order to avoid further litigation and to mitigate potentially adverse impacts on any particular rate group in this proceeding, the Settling Parties have agreed on how SCE's total revenue requirement shall be allocated to each rate group effective with Commission approval of this Agreement. Based on an estimate of SCE's expected system revenue requirement as of June 2006, the Phase 2 Revenue Allocation Agreement produces a specific rate group revenue change relative to the revenues assigned to each rate group as of December 2005.

ii. **June 2006 Revenue Allocation**

For bundled-service customers, based on the June 2006 estimated revenue requirement of $11,150.2 million, the total system percentage change in revenue requirement from December 2005 through June 2006 would be a 20.7% increase. The Settling Parties agree that all of SCE's CPUC- and FERC-authorized revenue requirements shall be allocated in proportion to the components as specified in Section 6.b.v, below, to produce the allocation of revenues and corresponding rate levels for each rate group proportional to those shown in Appendix B, and shall be adjusted to reflect SCE's actual total system revenue requirement when implemented.

ATTACHMENT A
SETTLEMENT AGREEMENT

Revenue changes and rates for DA customers based on the June 2006 estimated revenue requirement are also shown in Appendix B.

iii. **DA CRS Proceeding**

The Settling Parties also considered the expected revenue allocation impact resulting from R.02-01-011, the Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060 (the "DA CRS proceeding"). A working group in that proceeding has determined that the DA cost responsibility surcharge (CRS) paid by DA customers now exceeds the cost-based obligation to be paid by DA customers. The working group has determined that the rates that have been paid by bundled-service customers toward the obligation of DA customers, *i.e.*, the "DA loan," should be removed from bundled-service customers' rates and that any "DA loan repayment," *i.e.*, the current amounts paid by DA customers in excess of the cost-based obligation, should be credited to small and large bundled-service customers in the same proportion as such loan amounts were paid by small and large bundled-service customers. As a result, if the Commission adopts the working group report, the bundled-service large customer rate groups (TOU-8, GS-2, and TOU-GS-3) will receive net revenue decreases and the bundled-service small customer rate groups (Residential, GS-1, Agricultural and Pumping, and Street and Area Lighting) will receive net revenue increases that in total offset the revenue decreases provided to large bundled-service customer rate groups. This change in revenues allocated to small and large bundled-service customer rate groups does not result in a subsidy from small to large customer rate groups, but only reflects the modification of the prior treatment of DA CRS revenues. That revenue treatment is no longer appropriate given that

ATTACHMENT A
SETTLEMENT AGREEMENT

the cost-based obligation of DA customers has fallen below the amounts currently paid by those customers. The Settling Parties have assumed that the Commission will authorize the DA CRS revenue adjustment based on the working group recommendation and explicitly agree that any revenue allocation effects of DA CRS revenue adjustments on each rate group will be additive to the effect of the Phase 2 Settlement Agreement and shall be consistent with the Commission's final decision on the working group report in the DA CRS proceeding. Illustrative revenue allocation impacts of the working group recommendation taken from the DA CRS proceeding are also listed in Appendix B.

iv. **Adjustments To Revenue Requirements**

The levels of revenues and rates reflected in Appendix B assume that the Commission adopts ALJ Fukutome's proposed decision in Phase 1 of SCE's 2006 GRC in A.04-12-014, without any change to its proposed level of authorized revenues, and that the FERC adopts SCE's proposed rates in FERC Docket No. ER06-186. To the extent the revenue requirements assumed to result from these proceedings change, or the Commission adopts other revenue changes, the Settling Parties agree that such changes shall be reflected in the settlement revenues and average rates listed in Appendix B in proportion to the change in revenue requirement from the revenue requirements reflected in Appendix B of this Settlement. The Parties agree that SCE shall provide such changes to the assigned ALJ in this proceeding and to the Commission if such changes occur prior to the issuance of a Commission decision adopting this Agreement, and that the Commission should authorize SCE to make any necessary changes in revenues and rates by advice letter if such changes occur after the Commission has adopted this Agreement.

ATTACHMENT A
SETTLEMENT AGREEMENT

v. **Unbundled Revenue Requirements**

Without effecting any change to the agreed-upon Phase 2 Revenue Allocation Agreement in Appendix B, in order to produce unbundled rates for rate design purposes in this proceeding and to provide a basis for other revenue requirement changes occurring after this proceeding and before SCE's next revenue allocation proceeding, SCE's authorized revenue requirements shall be allocated to rate groups as follows:

a. **FERC-Jurisdictional, Transmission Revenue Requirement**

SCE's FERC-approved rates for transmission and SCE's forecast billing determinants shall be used to determine the transmission revenue requirement recovered from each rate group. Individual rate components adopted by FERC shall be added to the CPUC-jurisdictional rates, resulting in total delivery service rates.

b. **Distribution-Related Revenue Requirement**

1. SCE's CPUC-approved distribution revenue requirement shall be allocated to rate groups based on the marginal distribution costs defined in Section 6.a.iii of this Agreement, and based on the NCO marginal customer costs listed in Appendix G of Exhibit SCE-2 (Updated), with marginal customer cost revenue responsibility calculated based on these values. Marginal distribution cost revenues shall be calculated by applying the marginal distribution capacity costs to the diversified demands of various rate groups at the appropriate voltage levels. Because distribution rates are developed for all retail customers, marginal customer and distribution cost revenues are based on

ATTACHMENT A
SETTLEMENT AGREEMENT

combined direct-access (DA) and bundled-service demand and number of customers.

2. Large Power interruptible rate program credits shall be based upon SCE's forecast of program participation and credit levels. These costs shall be allocated to rate groups for recovery in distribution rates from bundled-service and DA customers based on the marginal generation cost allocator, which imputes marginal generation costs to DA customers in each rate group as if they were bundled-service customers.
3. Non-allocated revenues consist primarily of Street Lighting facilities costs and power factor adjustment revenues as derived by SCE. These revenues shall be assigned directly to the rate groups responsible for incurring the costs except that for purposes of this Agreement, non-allocated revenues assigned to the Street and Area Lighting rate group shall be capped as reflected in this Agreement, with the residual revenue deficiency resulting from this limit allocated among all rate groups on the same basis as distribution revenues.
4. The revenues associated with the discount provided to SCE's employees and retirees under Schedule DE shall be allocated to all other customers, except customers receiving the CARE discount, on a cents per kWh basis.

ATTACHMENT A
SETTLEMENT AGREEMENT

c. **Generation Revenue Requirement**

1. The DWR Revenue Requirement, net of contribution by DA customers, shall be combined with SCE's other generation-related revenue requirements, net of contribution by DA customers, and shall be allocated to rate groups for recovery from bundled-service customers based on marginal generation cost revenues.
2. For the purpose of this Agreement, SCE's generation revenue requirement, net of contributions from DA customers, that is allocated to each rate group shall be determined residually, *i.e.*, by subtracting the functional allocation of all other revenue requirements to each rate group from the total revenue requirement allocated to that rate group that is shown in the Phase 2 Revenue Allocation Agreement in Appendix B.
3. Generation-related administrative and general (A&G) costs are assumed to be reflected in SCE's generation revenue requirement and shall be recovered in SCE's generation rate component from bundled-service customers, provided the Commission does not modify this conclusion of ALJ Fukutome's proposed decision in A.04-12-014.

d. **DWR Bond Charge Revenue Requirement**

The DWR Bond Charge revenue requirement shall be recovered based on the DWR Bond Charge as authorized in the appropriate CPUC proceedings.

ATTACHMENT A
SETTLEMENT AGREEMENT

e. **DA Cost Responsibility Surcharge**

For the purpose of this Agreement, the full level of the 2006 DA CRS for DA customers is estimated to be 0.745 cents per kWh. Because the DA CRS is currently capped at 2.7 cents per kWh, the surplus revenue provided by DA customers relative to the cap shall be allocated to bundled-service customers based on the "small"/"large" customer allocation adopted in D. 03-07-030. However, any revenue allocation change resulting from a change in the DA CRS shall be implemented as discussed in Section 6.b.iii, above, and shall be consistent with the Commission's final decision on the working group report in R.02-01-011.

f. **Nuclear Decommissioning Revenue Requirement**

In accordance with D. 00-06-034, SCE's CPUC-jurisdictional nuclear decommissioning revenue requirement shall be allocated on an equal cents per kWh basis, reflecting total retail sales.

g. **Public Purpose Programs (PPP) Revenue Requirement**

SCE's CPUC-jurisdictional Public Purpose Programs revenue requirement shall be allocated using the current system average percentage (SAP) method and shall be based upon all retail sales, including DA sales (with generation imputed). The PPP revenue requirement allocated to each rate group in this manner shall be recovered from the customers of each respective rate group on a cents per kWh basis.

ATTACHMENT A
SETTLEMENT AGREEMENT

h. **Trust Transfer Amount Revenue Requirement**

The Trust Transfer Amount (TTA) revenue requirement is recovered through rates applicable to the residential and small commercial rate groups, the customer groups that received the 10 percent rate reduction implemented pursuant to Public Utilities Code Section 368. These rates are designed to recover the principal and interest on the bonds that were used to finance the rate reduction and are revised at least annually in accordance with a true-up mechanism approved in D. 97-09-056. SCE shall continue to include the currently-authorized TTA rates in the relevant residential and small commercial rate schedules.

i. **CARE Balancing Account Revenue Requirement**

The revenues associated with the discount provided to CARE customers shall be allocated to rate groups on an equal cents per kWh basis including DA sales, but excluding the kWh usage of CARE and Street and Area Lighting customers. The CARE revenue requirement shall be recovered through a surcharge added to all customers' rates, excluding CARE customers themselves and customers in the Street and Area Lighting rate group. The CARE surcharge is reflected in the PPP charge.

ATTACHMENT A
SETTLEMENT AGREEMENT

vi. **Future Changes To SCE's Consolidated Revenue Requirement**

The parties agree that distribution and generation revenue requirement changes occurring after the Commission has issued a decision in this proceeding and until SCE's next Phase 2 proceeding shall be allocated according to the functional character of the revenue requirement change on an SAPC basis. For example, revenue changes resulting from the ERRA proceeding shall be allocated on an SAPC basis, *i.e.*, a revised SCE generation revenue requirement would be combined with the DWR Power Charge revenue requirement to calculate an SAPC factor for the sum of SCE generation and DWR revenue requirements. The SAPC factor would then be applied to the combined generation rate, and then the adopted DWR Power Charge would be subtracted from the combined generation rate to calculate the SCE generation rate. Revenue requirement changes resulting from the reduction or elimination of the rate reduction bond repayment charge shall be allocated solely to residential customers and small commercial customers in the GS-1 rate group.

c. **Rate Design**

The Settling Parties agree that the results of the rate design process as shown by the rate schedules in Appendix C to this Agreement ("Phase 2 Rate Design Agreement") are reasonable and should be adopted by the Commission. Appendix C lists rates that reflect the Phase 2 Revenue Allocation Agreement, and the additive impact of the DA CRS revenue allocation adjustments. These rates are based on the estimated total system revenue requirement for June 2006 and shall be adjusted consistent with the terms of this Agreement to reflect SCE's actual total system revenue requirement when this Agreement is implemented and consistent with the Commission's final decision on the working group report in the DA CRS proceeding.

ATTACHMENT A
SETTLEMENT AGREEMENT

i. **Common Pricing Principles**

a. Except as otherwise specified in this Agreement or in Appendix C, customer charges shall be set at the full EPMC level for customers with demands of 20 kW or more who are served on TOU rate schedules. Customer charges for non-TOU rate schedules where customer charges are not currently set at the full EPMC level shall be increased by a maximum of 20 percent of the difference between the current customer charge and the EPMC level.

b. Time-related demand charges for distribution service shall be eliminated for all demand-metered rate schedules.

c. Consistent with elimination of separate revenue accounting treatment for DA service fees, and because at this time there is no cost basis to impose the current $5 per month fee on DA customers, Schedule DA-SF shall be eliminated without prejudice to the right of any party to raise this issue in an appropriate future proceeding.

ii. **Residential Rate Group**

a. Energy charges for SCE's Schedule D, and other comparable residential rate schedules shall reflect five tiers of consumption, *i.e.*, the baseline allocation (as applied in the existing manner to SCE's baseline zones), which is Tier 1; 101% to 130% of the baseline allocation, which is Tier 2; 131% to 200% of the baseline allocation, which is Tier 3; 201% to 300% of the baseline allocation, which is Tier 4; and 301% or more of the baseline allocation, which is Tier 5.

ATTACHMENT A
SETTLEMENT AGREEMENT

b. In accordance with the Commission's interpretation of Water Code Section 80110, the Basic Charge and energy rates for usage up to 130% of the baseline allocation shall not be increased above the levels effective on February 1, 2001. Revenue changes allocated to residential customers shall be reflected in the rates established for Tiers 3, 4, and 5. SCE shall establish the Tier 3 energy charge at 1.65 times the Tier 2 energy charge, with any additional revenue increases allocated to Tiers 4 and 5 in a manner that provides comparable increases from Tier 3 to Tier 4 and from Tier 4 to Tier 5.

c. Energy charges for Schedule D-CARE shall reflect three different charges, which increase from Tier 1 to Tier 2 and to Tier 3. The Tier 3 rate shall be established at a level that provides a discount of 20% (excluding the CARE surcharge component of the PPPC and DWR Bond Charge) from the Tier 3 rate level established for Schedule D. This is intended to result in Tier 3 rate for Schedule D-CARE (for all usage in excess of 130 percent of the baseline level) of approximately 17.6 cents per kWh, including the impact of revenue allocation increases resulting from DA CRS adjustments.

d. Energy charges for Schedule D-FERA shall reflect five tiers, as for Schedule D; however, energy rates for Tier 2 and Tier 3 shall be set at the same rate level.

e. The current meter charges for Schedules TOU-D-1 and TOU-D-2 shall not be increased. The differential between the cost-based level and current level of meter charges shall

ATTACHMENT A
SETTLEMENT AGREEMENT

be reflected in the distribution component of the energy charges.

f. The current customer charge for Schedule TOU-D-2 shall not be increased.

g. There shall be no change made to the current Basic Charge for residential service.

h. The discount provided to customers who provide submetered electric service and who are served on Schedule DMS-2 shall be $0.171 per space per day. This value reflects a cost-of-service discount of $0.30 with a diversity adjustment of $0.10 per space per day, and a Basic Charge adjustment of $-0.029 per space per day. The diversity adjustment for Schedules DM and DMS-1 shall also be $0.10 per space per day. In accordance with prior practice, the discount provided to customers served on Schedule DMS-1, shall be set at a level that maintains the current ratio (28.6%) between the submetering discounts for Schedules DMS-1 and DMS-2.

i. The distribution-related component of SCE’s residential rates is currently adjusted between the summer and winter seasons to moderate and to levelize the impact of increased base rate revenues collected during the summer season from customer demand charges. SCE shall revise the seasonal rate adjustment in residential distribution rate components, if necessary, to offset changes in distribution revenue recovery resulting from the elimination of time-related distribution demand charges for the demand-metered rate schedules.

ATTACHMENT A
SETTLEMENT AGREEMENT

j. All baseline allowances shall remain at their current levels. SCE has excluded the impact of seasonal residents from the determination of baseline allocations for zones 15 and 16. Baseline allowances for seasonal residents in zones 15 and 16 shall not be decreased because the Commission has determined that AB 1X prohibits any decrease in baseline allocations.

k. Medical baseline rates shall be designed as described in Exhibit SCE-4 (Updated).

iii. **Agricultural and Pumping Rate Groups**

TOU periods shall remain the same as currently specified in SCE's agricultural tariffs.

a. **PA-1 Rate Group**

The current rate structure consisting of a customer charge, connected load per horsepower service charge, a flat energy charge, and off-peak credit shall be maintained. The customer charge shall be set at the level listed in Appendix C. The off-peak credit shall continue to offset the distribution and generation components of the per-hp connected load charge. The connected load service charge shall be set at $1.74 per hp, which was the level in effect as of December 2005.

ATTACHMENT A
SETTLEMENT AGREEMENT

b. **PA-2 Rate Group**

The components of the current rate structure consisting of a monthly customer charge, a seasonally-differentiated flat energy charge, and a facilities-related demand charge shall be maintained but the seasonal time-related distribution demand charges shall be eliminated. The customer charge shall be increased by approximately 20% of the difference between the current level and the EPMC marginal cost-based level. Demand-related distribution costs shall be recovered through a facilities-related demand charge. This schedule shall be open only to agricultural service customers with peak demand below 200 kW.

c. **AG-TOU Rate Group**

1. Schedule TOU-PA (Options A and B)

   Option A consists of customer charge, and a connected load charge, combined with TOU energy charges. Option B consists of a customer charge, and a combination of time-related and facilities-related demand charges and TOU energy charges. The customer charge shall be increased by approximately 20% of the difference between the current level and the EPMC marginal cost-based level. The connected load charge for Option A and the summer time-related demand charge for generation for Option B shall be increased by approximately one-half of the difference between the current level and the marginal cost-based level. The off-peak energy charge for generation shall be set at approximately the off-peak generation

ATTACHMENT A
SETTLEMENT AGREEMENT

marginal energy cost. All remaining generation revenues shall be recovered through the on-peak and mid-peak energy charges.

2. The current rate structure for Schedule TOU-PA-SOP shall be maintained with the customer, demand, and energy charges determined on a basis consistent with Schedule TOU-PA-B.

d. **TOU-PA-5 Rate Group**

1. Schedule TOU-PA-5 shall remain the default rate schedule and consists of a customer charge, time-of-use and seasonally-differentiated energy charges, facilities-related and time-related demand charges. The customer charge shall be increased by approximately 20% of the difference between the current level and the EPMC marginal cost-based level. The on-peak time-related demand charge shall be increased by approximately one-half of the difference between the current level and the marginal cost-based level. The off-peak energy charge for generation shall be set at approximately the off-peak generation marginal energy cost. All remaining generation revenues shall be recovered through the on-peak and mid-peak energy charges.

2. Schedule TOU-PA-7 is designed as an option for pumping customers considering the use of alternatives to electric motor-driven pumps. Given that the operation of a diesel or natural gas motor-driven pump is now a more costly alternative than an electric motor, Schedule TOU-PA-7 rates shall be modified consistent

ATTACHMENT A
SETTLEMENT AGREEMENT

with changes made to the underlying tariffs in accordance with this Agreement, with rates moved 75% of the distance toward rates on the otherwise applicable tariff. This schedule shall be closed to new customers.

3. Schedule AP-I shall be retained, and the level of credit decreased to reflect an interruptible credit based on a generation marginal capacity cost of $74.69/kW.

iv. **Large Power Rate Groups**

All components of the current rate structure, consisting of a monthly customer charge, facilities-related demand charge, and seasonal time-related demand charges and TOU energy charges shall be maintained. The customer charge shall be established at the marginal cost-based level.

a. Rates for the large power rate groups shall be designed consistent with Appendix C.

b. Schedule I-6 shall be retained and revised to reflect an interruptible credit level of $74.69 per kW per year, differentiated by the applicable service voltage. Pursuant to D.05-04-053, SCE was ordered to begin a transition from the credit structure provided under Schedule I-6 to the credit structure provided under Schedule TOU Base Interruptible Program (TOU-BIP) over a three-year period. To implement the first step in this transition, the interruptible credit provided under Schedule I-6 shall be modified to shift 50% of the revenues currently associated with energy credits for this schedule to demand credits commencing with the first billing period for each I-6 customer account beginning after November 30, 2006. The

ATTACHMENT A
SETTLEMENT AGREEMENT

second step in the transition shall result in shifting the remaining 50% of the revenues currently associated with energy credits for this schedule to demand credits commencing with the first billing period for each I-6 customer account beginning after November 30, 2007. At this time, 20 percent of the credit revenues will be recovered through demand charge credits during the winter months. The interruptible credit will be applied to the demand charges in a manner reasonably consistent with the existing I-6 rate. At the end of the year following the second transition step, Schedule I-6 shall terminate.

c. Schedule TOU-BIP shall remain open to customers with demands in excess of 200 kW. Pursuant to D.05-04-053, the transition from Schedule I-6 to TOU-BIP is to occur with revenue neutrality relative to the amount of interruptible credits currently provided to customers on Schedule I-6. The interruptible credits provided under Schedule TOU-BIP shall be time-differentiated based on the loss of load probabilities listed in Section 6.a.i, above, and shall be scaled to provide the same total revenue credit currently provided under Schedule I-6 on a seasonal basis. The interruptible credits for Schedule TOU-BIP shall be applied to the average on-peak and average mid-peak demands during the summer season and to the average mid-peak demand during the winter season with 80 percent of the credits assigned to the summer and 20 percent of the credits assigned to the winter. The summer credits shall be applied to summer on-peak and mid-peak periods with 75

ATTACHMENT A
SETTLEMENT AGREEMENT

percent assigned to the on-peak period and 25 percent assigned to the mid-peak period.

d. Schedule RTP-2 shall be modified consistent with changes to the otherwise applicable tariff schedules, with hourly avoided costs scaled so that the hourly rates shall be designed to recover the total revenues allocated to each rate group.

e. Schedules RTP-2-I and TOU-8-SOP shall be eliminated.

v. **Small and Medium Commercial Rate Group**

a. **GS-1 Rate Group**

For Schedule GS-1, the current rate structure consisting of a customer charge and an energy charge differentiated by summer and winter seasons shall be maintained. The customer charge for Schedules GS-1 and TOU-GS-1 shall be maintained at the current level of $0.43/day.

b. **GS-2 Rate Group**

For Schedule GS-2, the components of the current rate structure consisting of a monthly customer charge, seasonal time-related demand charges, and a facilities-related demand charge, and a flat energy charge that is differentiated between the summer and winter seasons shall be maintained. Schedule GS-2 and all other optional schedules designed for the GS-2 rate group shall be available only to customers with peak demand below 200 kW. The customer charge shall be increased by approximately 20% of the difference between the current level and the EPMC marginal cost-based level. A TOU metering charge shall apply to customers selecting either of

ATTACHMENT A
SETTLEMENT AGREEMENT

the TOU energy pricing options offered under Schedule GS-2. The cost of the TOU meter options for customers in the GS-2 rate group shall be established at the levels indicated in Appendix C.

c. **TOU-GS-3 Rate Group**

Commercial customers with peak demands of 200 kW or greater but less than 500 kW shall be assigned to a new rate group, designated as TOU-GS-3. This naming convention shall be used to provide a clearer distinction between the GS-2 rate group, which applies to customer accounts with demands of less than 200 kW, and TOU-GS-3.

1. For Schedule TOU-GS-3, the components of the current TOU-GS-2 rate structure, consisting of a customer charge, a facilities-related demand charge, a seasonally- and TOU-differentiated demand charge, and seasonally- and TOU-differentiated energy charges shall be maintained, but with revisions as needed to reflect the revised load profile and billing determinants of the new TOU-GS-3 rate group. The customer charge shall be increased to the EPMC marginal cost-based level. Energy prices shall be revised based on marginal generation and marginal energy prices.
2. Schedule TOU-GS-SOP shall be retained as an option in the TOU-GS-3 rate group
3. Schedule TOU-EV-4 shall be retained as an option available to commercial customers with monthly demands between 200 kW and 500 kW.

ATTACHMENT A
SETTLEMENT AGREEMENT

d. In addition to a cost-based TOU option, a second TOU rate option shall be made available to customers in the GS-2 and TOU-GS-3 rate groups.

1. For Schedule GS-2, SCE shall establish a TOU energy only option that shall be comprised of TOU energy charges designed to collect all applicable generation revenues. Customer charges and non-generation facilities-related demand charges otherwise applicable to Schedule GS-2, and a TOU meter charge shall apply to this TOU option.
2. For Schedule TOU-GS-3, SCE shall revise Option A and it shall be comprised of TOU energy charges designed to collect all applicable generation revenues. Customer and non-generation facilities-related demand charges otherwise applicable to Schedule TOU-GS-3 shall apply to this option.

vi. **Street and Area Lighting Rate Group**

The current rate structure, consisting of monthly customer charges, energy charges for metered schedules, and per-lamp non-energy charges shall be maintained for all lighting schedules.

a. Energy charges shall be modified to reflect allocated distribution and generation revenues as indicated in Appendix C.
b. Special Condition 6 of SCE's Schedule LS-1 shall be modified to specify that whenever a customer orders removal of street lighting service and facilities and such facilities were in service for less than 10 years (120 consecutive months), the customer shall pay to SCE an amount equal to the total estimated

ATTACHMENT A
SETTLEMENT AGREEMENT

installed cost less any customer contribution plus the estimated removal cost less the estimated net salvage value of the facilities. If a customer orders removal of street lighting service and facilities after 10 years, there shall be no cost assessed to the customer.

c. Lamp charges for Schedule LS-2 shall be reclassified into options A and B) to differentiate between a single feed point to a customer-owned street lighting system (more than one light fixture) and a service connection to a customer-owned street light (one light fixture). A customer-owned photocell shall be required under Schedule LS-2 Option B, with a corresponding reduction in the lamp charge in recognition of the customer's costs of ownership and operation of the photocell.

d. The optional relamp service provided under Schedules LS-2 and LS-3 shall be closed to new lamp installations.

vii. **Traffic Control Rate Group**

The current rate structure, consisting of a daily customer (meter) charge and energy charges shall be maintained. The customer charge shall be set at the full marginal cost-based level. The remaining revenue allocated to the traffic control rate group shall be reflected in energy charges for the group.

viii. **Standby**

The following changes in SCE's Standby tariff (Schedule S) or procedures shall be implemented:

a. **Notification of Scheduled Outages**

Special Condition 6 of Schedule S shall be modified to require customers to provide advance notice to SCE, via the Automated Standby Customer Information Hotline of a request

ATTACHMENT A
SETTLEMENT AGREEMENT

for Maintenance Service. See Appendix D for a pro forma representation of the tariff language.

b. **Application of Interruptible Rates**

Schedule S shall be modified to permit customers to participate in Schedule TOU-BIP applied to their Supplemental, Backup Service and Maintenance Service as defined in Schedule S and to receive interruptible credits consistent with Schedule TOU-BIP. This option shall become available beginning with the first billing period after November 30, 2006.

c. **Real-Time Pricing Option**

SCE shall within 18 months of the effective date of this Agreement evaluate, with the participation of CAC/EPUC, CLECA, and CMTA, a real time pricing option that may augment or replace the current option of pricing the URG portion of the Schedule S generation charges in accordance with Schedule PC-TBS.

7. Implementation of Agreement

It is the intent of the Parties and their request that the Commission adopt this Agreement on an expedited basis. Furthermore, it is the intent of the parties that SCE should be authorized to implement the rates resulting from this Agreement as soon as practicable following the issuance of a final Commission decision approving this Agreement.

8. Incorporation of Complete Agreement

This Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Parties acknowledge that changes, concessions, or compromises by a Party or Parties in one section of this Agreement resulted in

ATTACHMENT A
SETTLEMENT AGREEMENT

changes, concessions, or compromises by the Parties in other sections. Consequently, the Parties agree to oppose any modification of this Agreement not agreed to by all Parties.

9. Signature Date

This Agreement shall become binding as of the last signature date of the Settling Parties.

10. Regulatory Approval

The Parties shall use their best efforts to obtain Commission approval of the Agreement. The Parties shall jointly request that the Commission: (1) approve the Agreement without change; and (2) find the Agreement to be reasonable, consistent with law and in the public interest.

11. Compromise Of Disputed Claims

This Agreement represents a compromise of disputed claims between the Parties. The Parties have reached this Agreement after taking into account the possibility that each Party may or may not prevail on any given issue. The Parties assert that this Agreement is reasonable, consistent with law and in the public interest.

12. Non Precedent

Consistent with Rule 51.8 of the Commission's Rules of Practice and Procedure, this Agreement is not precedential in any other proceeding before this Commission, except as expressly provided in this Agreement.

13. Previous Communications

The Agreement contains the entire agreement and understanding between the Parties as to the subject matter of this Agreement, and supersedes all prior agreements, commitments, representation, and discussions between the Parties. In the event there is any conflict between the terms and scope of the Agreement

ATTACHMENT A
SETTLEMENT AGREEMENT

and the terms and scope of the accompanying joint motion, the Agreement shall govern.

14. Non Waiver

None of the provisions of this Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

15. Effect Of Subject Headings

Subject headings in this Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

16. Governing Law

This Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

17. Number Of Originals

This Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

ATTACHMENT A
SETTLEMENT AGREEMENT

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce A. Reed

Title: Senior Counsel Date: 4/06/2006

DIVISION OF RATEPAYER ADVOCATES

By: /s/ Dana Appling

Title: Director Date: 4/05/2006

THE UTILITY REFORM NETWORK

By: /s/ Michel P. Florio

Title: Senior Attorney Date: 4/06/2006

CALIFORNIA FARM BUREAU FEDERATION

By: /s/ Ron Liebert

Title: Associate Counsel Date: 4/05/2006

AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

By: /s/ Dan Geis

Title: Assistant Executive Director Date: 4/06/2006

FEDERAL EXECUTIVE AGENCIES

By: /s/ Norman Furuta

Title: Associate Counsel Date: 4/06/2006

ATTACHMENT A
SETTLEMENT AGREEMENT

CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION

By: /s/ Keith R. McCrea

Title: Attorney Date: 4/06/2006

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By: /s/ William H. Booth

Title: Attorney Date: 4/05/2006

INDICATED COMMERCIAL PARTIES
Manatt, Phelps & Phillips, LLP

By: /s/ Randall W. Keen

Title: Attorneys for Indicated Commercial Parties Date: 4/06/2006

BOMA

By: /s/ B. F. Roberts

Title: President, Economic Sciences Corp. Date: 4/06/2006

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

By: /s/ Reed V. Schmidt

Title: Energy Consultant Date: 4/06/2006

ATTACHMENT A
SETTLEMENT AGREEMENT

Vote Solar

By: /s/ J. P. Ross

Title: Director of Programs Date: 4/06/2006

WESTERN MANUFACTURED HOUSING COMMUNITY ASSOCIATION

By: /s/ Edward G. Poole

Title: Counsel Date: 4/05/2006

COGENERATION ASSOCIATION OF CALIFORNIA AND ENERGY PRODUCERS AND USERS COALITION

By: /s/ Nora E. Sheriff

Title: Counsel Date: 4/06/2006

(END OF ATTACHMENT A)